which we analyze in this manner varies with demand. There are, however, no statistical tests for certain basics. The analyst must ensure that over the period there have been no changes in technology or planning criteria that alter the relationship of demand to investment. In such a case, even though the basic statistical tests may still indicate statistically "valid" results, the theoretical basis of the inference would be destroyed. Later in this section, we will expand upon the complexities of the statistical approach.

Many utilities do not keep their books and records in a manner facilitating the year-by-year analysis of the various cost components of the distribution system. Distribution engineers, on the other hand, do tend to measure trends and attempt to estimate the total cost of meeting load and customer growth. Their estimates can reasonably be considered to represent extensions of past trends modified by expected changes in technology. Since this and other factors often render the statistical approach unusable (see pages 86 to 87), we have developed a third method which we would use if our preferred approach is not feasible.

We will describe and illustrate the use of the third method, which is shown in Table 8. To derive the marginal investment in demand-related distribution facilities, gross additions to distribution plant in constant dollars are analyzed for a past period and a prospective period. An analysis period encompassing both past and projected investments permits the recognition of extraordinary investment items, changing optimality criteria or improved technologies. In this way, a period of gross additions to distribution plant that will best represent the future level of marginal demand-related distribution costs can be selected. The chosen period of distribution plant additions becomes the basis of the marginal demand-related distribution cost calculation. First, expenditures for replacements of existing plant which are not related to additions[25] to load and customer-related distribution plant are deducted from gross additions to distribution plant. The resulting figure, demand-related additions to plant, is then divided by the additional coincident peak load added to the distribution system during the analysis period to obtain the marginal demand-related investment cost in distribution facilities.

In the example, we show the analysis only for the future period. Actually, we performed the computation for the historic period also. We found for the historic period a unit cost (in constant dollars) significantly higher than the unit cost for the future period. We have discussed the situation with distribution planners and have been told that the

[25] Customer-related distribution plant additions are defined as the product of the marginal per-customer cost (described in pages 74 to 76) and the number of customers added during the chosen period of analysis.

optimality criteria upon which distribution is planned have been changed. Since we are concerned with future marginal costs, we did not use the historical analysis.

A major part of the method described above is determining the load that should be used to unitize distribution investment. Once again, we must return to the planning process. In planning for a distribution system, it makes economic sense to plan well ahead. The labor involved in replacing wires as demand grows is too expensive to warrant sizing wires to current demand: a trade-off is made between the extra cost of installing more wire capacity than is needed this year and the cost of continually replacing it. Also, while a wire which is sized exactly to maximum demand will carry the load, the losses are reduced if the wire is sized larger, and a similar trade-off can be made on the optimum size of wire to carry a given expected load at minimum cost of wire and losses. These two trade-offs lead to most distribution systems being sized somewhat larger than the maximum load at any point in time, not simply to provide a reserve margin but because of the economics of the distribution system itself. As with the costs of generating capacity, distribution capacity-related costs are common over time (i.e., the capacity available today is there because of an anticipated aggregate load). The cost we seek is the per-unit cost of capacity when the optimum loading for which we planned has been achieved.

Therefore, determining the load by which we unitize gross investment requires understanding of the planner's optimality criteria.

The analyst's most important guide, once again, is that costs must be related to the causative factor. As with transmission investment, a look at the planning process and discussion with planners are necessary. In the next portion of this section, we will discuss those factors complicating the analysis of distribution costs.

C. Complexities of Distribution Investment

As with transmission, there are several complexities which may arise when analyzing distribution investment. In developing marginal demand-related distribution costs, as in developing transmission costs, the analyst must segregate the cost of replacement of old facilities, upgrading those facilities to meet new standards, and any other cost which is clearly not related to demand. At the risk of being repetitious, let us emphasize that the analyst must ensure that the investment and load being compared are truly in phase. These principles apply to either of the methods we recommend.

Turning to the specific methodologies, there are some guidelines that prove useful. We have stated that regression analysis is our preferred method if there have been no changes in technology or planning optimality criteria and if data are available. Technology, of course, is never constant. If, however, the rate of change in technology has been gradual and is expected to continue at the same gradual rate, the regression result should prove an accurate predictor. If, however, a big change was made, such as a switch from manual to automated construction equipment, from an overhead to an underground system, or from a smaller to a larger size transformer, the data reflecting events before the change should not be used to predict future cost levels. If the change in technology was long enough ago to leave sufficient observations (ten is the minimum that we would suggest), the statistical method can still be used. The same applies to any changes in the planning optimality criteria which have been discussed previously. If the planner's data base does not contain enough years of observations to yield valid statistical results or if any changes in technology or optimality criteria are expected in the near future, regression analysis should not be used.

It is extremely important to convert investment figures to constant dollars correctly. The best method to use is to choose a base year and convert total demand-related investment, on an account-by-account basis, to constant dollars using a construction cost index such as Handy-Whitman or, preferably, one developed by the company. From that base year forward, annual additions to plant, on an account-by-account basis, should be converted to constant dollars using the index for the appropriate year and should be added to the base year investment (in constant dollars) to derive successive years' total demand-related investment.

In using the alternate method, the analyst must also convert investments to constant dollars. Once again, a construction cost index should be applied on an account-by-account basis. The analyst ideally should inflate gross additions to distribution plant by the appropriate cost index and, based on discussions with planning personnel, estimate and subtract an allowance for replacement or retirement not related to incremental demand.

In calculating estimated customer-related additions to distribution plant, the analyst must determine whether the marginal per-customer cost is applicable to the incremental mix of customers. If density is changing, the customer cost component used to calculate customer-related additions should be based upon the incremental mix.

When deriving the demand-related component of distribution investment, the analyst must determine whether to subtract from total investment the marginal customer-related cost pertaining to the period analyzed or to subtract the average marginal customer-related cost for all consumers on the system.

Finally, we will repeat the rule that is basic to transmission and distribution analysis. The analyst must understand the potentially arbitrary nature of the accounting system and, where necessary, reclassify costs between distribution and transmission based on the functional operation of equipment and not the accounting rules.

D. Distribution O&M Expenses

Distribution O&M costs are occasioned chiefly by exposure of the system to the natural hazards of weather and time. To an extent, these expenses will vary with demand. This extent, however, is quite difficult to measure. Theoretically, the demand-related portion of distribution O&M expenses is the difference between the current level of these expenses and the level that would exist in a minimum demand system. It is, however, inappropriate to allocate these expenses between demand-related and customer-related categories by means of the ratio of incremental demand-related distribution investment to incremental customer-related distribution investment. This is inappropriate because distribution O&M expenses are caused, to a large degree, by exposure of the system to exogenous forces and do not vary proportionally with additions to distribution system demand. Since it will probably be impossible to measure our theoretical definition of demand-related expenses, let us examine some expenses and see to what they are causally related. In this discussion, we will concentrate on explaining how we calculate per-customer and per-kilowatt distribution O&M expenses. Rather than repeat our overview on distribution costs, we assume that the reader has reviewed the previous portion of this discussion.

Distribution substations, for example, are related primarily to demand. In a system without demand, large numbers of substations would not be necessary. As demand increases, station investment will, as a rule, increase and station O&M expenses will increase. These expenses should therefore be considered almost 100 percent demand-related. In the case of a line that was felled in a hurricane, the incident occurred without regard to the size of the line and, therefore, the maintenance costs of restoring the line--chiefly labor (remember, in many instances, new conductors and equipment will be capitalized)--will not vary with size of the line. These expenses cannot be considered demand-related and should be charged on a per-customer basis. Turning to the example of a pole with guy wire that is dislocated by a car, we find a more complex situation. The cost of returning the pole to its original condition will not vary with pole size and is not demand-related. The very existence of the guy wire, however, is related to the presence of the conductor, which, in turn, is related to demand. The cost of reguying the pole may, therefore, be demand-related.

The only possible way to divide total distribution O&M expenses between those that are demand-related and charged on a per-kilowatt basis and those that will be charged on a per-customer basis is, on a company-by-company basis, to either sample work orders, make a judgmental decision on the basis described above, or rely on the opinion of someone knowledgeable about the particular system. In the past, we have found that, as a general rule, distribution O&M expenses, excluding street lighting expenses and associated overheads, are generally split about 60 percent customer-related and 40 percent demand-related.

In analyzing distribution O&M expenses, we prefer to look forward and backward five years. Prospectively and retrospectively, we seek distribution expenses on an account-by-account basis (e.g., FPC account). The first step is to segregate street lighting expenses and associated overheads from other expenses. These expenses are directly attributable to a small group of customers and should not be spread across all customers. Next, extraordinary and nonrecurring expenses must be separated. This would include expenses due to hurricane damage and credits from insurance received due to such occurrences. Any divergence from the historical pattern should be brought to the attention of operating personnel. Once the data have been thoroughly examined and all street lighting-related expenses removed, the expenses must be divided between the demand-related and customer-related categories of expenses. Total demand-related expenses are divided by distribution system demand at time of system peak to arrive at a per-kilowatt cost. Customer-related expenses are divided by total customers served from the distribution system to arrive at a per-customer cost. These unit costs are then converted to constant dollars, using an appropriate index. Once in constant dollars, the trend in these costs is examined and a level of costs is extrapolated to several years into the future. For purposes of stability in ratemaking, we feel that a single cost level, representing the midpoint of a longer period within which technology is relatively constant, is preferable to annual changes in rates to reflect the trend of expenses.

Table 9 shows a sample calculation of distribution expenses. As footnote one indicates, the total distribution expenses in Column (1) exclude street lighting expenses and associated overheads. Based on our analyses and on discussions with distribution operating personnel, 60 percent of these expenses were allocated to the customer-related expenses and divided by average customers less street lighting customers plus locked meters (reflecting currently inactive customer locations). This yielded a unit customer cost. The remaining 40 percent of distribution expenses are demand-related and were divided by peak distribution demand to obtain a per-kilowatt distribution expense. Both unit customer- and demand-related expenses were converted to constant dollars using an electric labor cost index[26] appropriate to this utility. Since customer-related expenses in constant dollars were stable over the period analyzed, we chose the average of the five years' expenses as representative of the constant dollar level of expenses in the future. Since demand-related expenses exhibited a declining trend, we performed a time series regression of these expenses and, based upon this trend, extrapolated to a constant dollar expense level several years into the future.

[26] In other cases, another kind of index may be more appropriate.

VIII. OTHER COSTS

A. Customer Accounts and Sales Expenses

Customer accounts expenses, comprised mainly of meter and billing expenses, are costs that are directly attributable to the addition of a customer to the system. Sales expenses, which take into account the costs of disseminating information to consumers (i.e., demonstration services and advertising expenditures), vary in proportion to the number of customers on the system. Hence, these expenses are properly included in the marginal costing study as customer-related unit expenses.

Customer accounts expenses and sales expenses are each analyzed for an historic period. As shown in Tables 10 and 11, annual expenses are divided by average annual number of customers to obtain annual unit costs per customer. These resultant figures are then divided by an overall weighting factor. This weighting factor, which is a customer-weighted average of individual class weighting factors, reflects the difference in costs associated with servicing the various classes of customers. Individual class weighting factors are based on the experience of the specific utility in question. For example, if for a particular utility residential meters are read every two months, whereas commercial meters are read every month, and the cost of each reading is the same, the residential class would receive a weight of one and the commercial class a weight of two for the meter-reading component of customer accounts expenses.

Company cost-of-service studies usually provide an analysis of these expenses, by account, allocated to customer classes and the average number of customers in each class, which are the necessary inputs to the derivation of individual class weighting factors.

The expense per weighted customer for each year is then converted to constant dollars using an appropriate cost index. Finally, the trend of these unit expenses is examined in order to obtain the levels of expenditures most representative of the near future. The next step, as shown in Tables 12 and 13, is to derive the expense per customer, by customer class, using the estimated expenses for the planning period for customer accounts expense and sales expense and the individual class weighting factors.

B. <u>Administrative and General Expenses</u>

Thus far, our analysis of the marginal costing procedure has not yet considered administrative and general (A&G) expenses. Nevertheless, since the expenses included in this category are a function of costs in other sectors of the utility's operations and, thus, are marginal costs, they cannot remain unaccounted for.

These expenses consist of such items as administrative salaries, office supplies, pensions and property insurance and will rise as utility service is expanded. While the president's salary will not rise with demand, eventually the company will grow to a level where a new vice president may be added. Similarly, while growth may not result in a constant expansion of general office facilities as utilities grow, eventually there will come a point where office facilities are expanded. Pensions obviously depend upon the number of employees which, in turn, will vary with such factors as increases in customers and demand. The marginal increase in administrative and general expenses does not, therefore, at any one time, necessarily bear the same relationship to other marginal expenses as total A&G expenses bear to other total expenses. Moreover, there may be an invariant portion of, as well as substantial economies of scale in, A&G expenses. In the past, we have developed marginal A&G loading factors assuming that these expenses will continue to bear the existing relationship to other marginal expenses. Since A&G expenses (in general) total only about 2 percent of marginal costs and are often a relatively insignificant part of the difference between marginal cost and the revenue requirement, we feel that a more detailed analysis of these expenses is necessary only if it would change the relative magnitude of the customer, capacity and energy components of marginal cost or if marginal costs fall within only a few percent of the revenue requirement. The methodology that we propose to use in developing A&G loading factors may not exactly measure the absolute marginal magnitude of these expenses, but does correctly divide these expenses between the customer, capacity and energy components.

In our example on Table 14, we classify administrative and general expenses into three categories: (1) those applicable to managerial effort, (2) those applicable to labor (this includes social security and unemployment taxes) and (3) those applicable to plant. Expenses applicable to managerial effort and labor are allocated between expenses applicable to energy-related O&M expenses and expenses applicable to other than energy-related O&M expenses. This is done on the basis of the ratio of the appropriate category of energy-related O&M expenses to total O&M expenses less A&G expenses. Energy-related O&M expenses are discussed in Section V.

Energy-related A&G expenses, which consist of the expenses dealing with the administration and general expenses of fuel and variable power production O&M expenses, are divided by total electricity generated and purchased to arrive at a per-kilowatt-hour A&G expense. This cost is a marginal cost attributable to each kilowatt-hour consumed.

A&G expenses applicable to other than energy-related O&M expenses are divided by total O&M expenses less A&G and energy-related O&M expenses. This yields an A&G loading factor which, when applied to marginal O&M costs, will account for the increase in A&G expenses that will result from an increase in O&M expenses caused by additional demand or additional customers. This factor is applied in calculating costing period capacity and customer costs.

A&G expenses applicable to plant are divided by total gross investment. This yields a loading factor that, when applied to long-run marginal unit investment, will cover the increase in A&G expenses occasioned by such investment. This factor is added to the percentage carrying charge.

A&G expenses should be calculated for an historic period of three to five years and any trends should be taken into consideration. As we find that A&G loading factors tend to remain stable, we have, in the past, usually chosen the most recent year's analysis for use in marginal costing studies.

IX. COMPUTATION OF CARRYING CHARGES

After developing the long-run marginal unit investments, it is necessary to determine how these investments should be converted into a marginal carrying charge for use in ratemaking. There are several approaches to the computations of carrying charges. All, however, are based upon the utility engineer's computation of the present value of the stream of charges that will arise from incremental capital investment under prevailing regulatory prescriptions. In this section, we will describe this computation (referred to as the engineer's approach) and discuss the ways in which carrying charges can be derived based on the results of the engineer's computation.

The goal of the economist in computing a carrying charge is not to simulate the regulatory process as the utility engineer must, but to simulate the carrying charge that would arise in a competitive marketplace. In a sense, the economist's method is an extension of the engineer's work since both look at the present discounted value of the same stream of costs. Since the engineer is concerned chiefly with choosing a least cost investment plan, he can use and compare the present discounted value computations from alternative investment programs. The economist must go one step further. He is concerned not only with the present discounted value of future costs but also with the appropriate distribution of these costs over the life of the equipment. In the past, we have converted the engineer's calculation into a levelized annual carrying charge. In times of slight inflation and/or technical progress, this works well. However, the presence of either significant inflation and/or significant technical progress causes that method to yield a poor approximation of the marginal economic cost of investing in long-lived equipment. This is discussed at pages 90-94 and Attachment C of Topic 1.3, where we reach the conclusion that in such times we considerably overstate cost where we use marginal investment costs and accounting depreciation rates. It is for this reason that we prefer to use the economist's approach (that recognizes the effects of inflation) to carrying charges. We are not recommending that industry accounting practices and revenue requirements determined by regulatory commissions be converted to those implicit in the economist's approach, although we note that the accounting profession is attempting to grapple with this problem; our approach may have application in this context also. Our concern in computing marginal costs is that competitive industries, operating under restrictions of the marketplace, base their decisions upon this economic approach and, if consumers are to make choices between electricity consumption and competing goods and services, they should make their decisions faced with costs having the same economic basis.

Part A of this discussion describes how to make the engineer's computation of the revenue requirements. There is also a sample of this computation. Part B discusses how inflation and technical progress affect prices in the competitive market and how the analyst can account for this in computing the carrying charges on marginal investment. Sample computations also accompany the discussion in Part B.

A. The Engineer's Approach

Engineers for utilities have long sought to evaluate alternative potential investments based on the relative present value of all revenue requirements arising from these investments. In the process, they have developed sophisticated methods of analysis which facilitate the calculation of the entire stream of costs that will arise from a capital investment. The marginal cost of capacity to the company over time is the full set of charges that will arise from the investment. Thus, in developing carrying charges, we have, in the past, found it useful to draw upon the engineer's approach.

The engineer recognizes that a capital investment gives rise to three basic types of charges: taxes, return of capital (depreciation) and return on capital (earnings and interest). He further assumes that investments are financed at the incremental cost of capital. He next seeks to simulate the accounting charges that will arise from a particular investment. He accepts as given the regulatory criterion of the revenue requirement being equal to the sum of taxes on earnings and property, depreciation on plant that is used and useful and earnings on net plant that is used and useful.[27] Therefore, to compute the charges, he must predict the service life and probable dispersion pattern of retirements for the investment. Once he has done this, he has a stream of mean annual surviving investments to which he can apply the straight-line rate of depreciation and compute all the calculations that he would expect a regulatory body to make in determining the company's revenue requirement. After calculating the charges that will arise in each year over the life of the plant, he calculates the sum of the present worth of the revenue requirements for various investments to determine which investment is least costly.

The first step in computing carrying charges is to determine a service life and survivor curve for the investment category being analyzed. A sufficient degree of precision can be obtained by computing carrying charges separately for the three major functions. Within each function, there are a number of accounts and subaccounts with different service lives and survivor curves. From these a composite service life and survivor curve must be chosen. Ideally, the composite would be determined by developing a weighted average service life and composite survivor curve based on forecast investment in each account. Since the latter information is rarely available, sufficient precision can be obtained by developing a

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27 There may be other items, such as insurance, which are costs relevant to a particular investment which the engineer will take into consideration. For clarity's sake, we will not discuss these charges here.

weighted average service life based on historic investment and choosing a survivor curve typical of the predominant accounts in the function. While, of course, some degree of precision is sacrificed when moving from the ideal situation, sensitivity analyses have shown that only a gross error in the choice of a survivor curve will significantly affect the results of the analysis. Although some engineers hesitate to suggest overall function survivor curves, the informed judgment of personnel involved in these types of analyses is the best method of choosing a survivor curve.

In a case where companies have had no experience with dispersion studies and cannot justify the cost of such studies, survivor curves by function, sufficient for this purpose, could be determined by consulting with other utilities.

The next step is the determination of the incremental cost of capital (overall cost of capital). This is based on the forecast costs of long-term debt, preferred stock financing and common equity financing. Forecasts of the costs of long-term debt and preferred stock are usually accomplished by studies of the costs of recent issues of similarly rated companies or reference to the crystal ball. The incremental equity cost is taken as the company's currently allowed equity return, or, if it is different, the return that the company will need to attract sufficient capital in the prospective period. The weighted average cost of capital is calculated based on the proportion of incremental financing from each source. It must be remembered that, as coverage requirements change and as the relative costs of various types of financing change, the incremental financial structure will often deviate from the existing financial structure. For this computation, historic data are almost never sufficient.

The weighted average incremental cost of capital will be used as the rate at which the revenue requirements and the mean annual surviving investment are discounted. The combined preferred and common equity cost components of the overall cost of capital will be used to calculate equity return. The debt component of the overall cost of capital will be used to calculate interest return. These components are calculated separately for income tax purposes. In jurisdictions where regulatory bodies insist that tax reserves be included at no cost in the capital structure, this should be taken into account in the determination of the incremental cost of capital.

A sample of this calculation is provided in Table 15. Accompanying the sample in Table 15 is a description of the specific calculation. Remember, we are chiefly interested in the final result of this computation: the present value of the revenue requirements.

Having determined the service life and survivor curve, we can hypothesize a $1,000 investment and determine for each year of the plant's life the value of the surviving investment, as well as the value of the retirements in each year. By applying a straightline book depreciation rate to the surviving investment in each year, book depreciation is determined. On an overall basis, the assumption that salvage value equals the cost of removal is generally valid. If this is not the case, the depreciation rate should be changed accordingly. A book depreciation reserve is calculated by summing accrued depreciation and subtracting accrued retirements.

The mean net book investment is calculated by subtracting the book depreciation reserve from the mean annual surviving investment. The mean net investment (rate base applicable to capital investment) is the mean net book investment less any reserve for deferred taxes mandated by the regulatory body.

At this point, it is necessary to detour and discuss whether taxes should be included in marginal cost. Theoretically, a case can be made that the marginal resource cost of electricity should not include any tax component. If marginal costs excluding taxes were computed and used as prices, however, electricity would be underpriced in relation to competing energy sources, all of which are taxed. In computing marginal costs upon which allocation decisions will be made, it is of paramount importance that the calculations of the cost of different goods are compatible. From a second-best viewpoint, if society has chosen to allocate social costs through a method of taxation on income and property and if, as a result of an increase in demand for a good these taxes increase, this increase in taxes, if applied on a uniform basis to all, is a proper marginal resource cost. The treatment of tax depreciation in determining revenue requirements usually reflects the prescriptions of the regulatory authority. There are different types of tax depreciation allowed under federal statutes, and tax lives based on the IRS's asset depreciation ranges differ from book life. Tax depreciation is calculated using the type of depreciation and tax lives used by the company. Deferred income tax is derived by subtracting book depreciation from tax depreciation and multiplying by the effective tax rate. The reserve for deferred taxes is the accrued deferred tax.

If the company flows through deferred taxes, there is no need to calculate either deferred income tax or the deferred tax reserve. If the company normalizes deferred taxes, the deferred tax is added to the annual revenue requirement. This has the effect of increasing the revenue requirements in the early years of the investment and decreasing the revenue requirements by a corresponding amount in the later years of the plant's life. Essentially, under normalization, the company benefits by the time value of money. This is the reason that many commissions require that the deferred tax reserve be either deducted from rate base or included in capitalization at a zero cost of capital.

Allowances must also be made for treatment of the investment tax credit. There are several methods currently in use. We will discuss only the most common, the ratable flow-through method. Under this method, the investment tax credit is added to the company's revenue requirement in the first year. A reserve is set up and amortized equally over each year of book life. The amortization is deducted annually from the revenue requirements. Once again, the company receives the benefit of the time value of money. The reserve, however, is not deducted from rate base or included in capitalization at a zero cost of capital by direction of the federal government.

Equity return is the equity component of the weighted average incremental cost of capital times mean net investment. Interest is the interest (long-term debt) component of the cost of capital times mean net investment. Taxable income is determined by subtracting tax depreciation and, if applicable, the amortized investment tax credit from the sum of book depreciation, equity return and, if normalization is used, deferred income tax and dividing this result by one minus the tax rate. Income tax is calculated by multiplying taxable income by the tax rate and adjusting for the investment tax credit in the first year. The income tax so calculated simulates the actual tax payment that the project will be responsible for, including any revenue requirement brought about by normalization of deferred taxes.

Property or ad valorem tax should be taken into account. An effective property tax rate relative to gross plant, mean net book investment or mean net investment should be determined and each year's property tax calculated. For example, if a property tax rate applicable to gross plant is determined, annual property tax payments can be simulated by multiplying this rate times the mean annual surviving investment.

With all this information, the determination of the annual revenue requirement relative to capital investment is simply a matter of addition. In all cases, the revenue requirement consists of book depreciation, equity return, interest, property tax and income tax. If deferred income tax is normalized, this value must be added to the revenue requirement. If the investment tax credit is either fully normalized or ratably flowed through, this value must be added to the first year's revenue requirement. In addition, if the ratable flow-through method is used, the amortized investment tax credit must be deducted from the revenue requirement over the book life of the original investment.

The next step is the calculation of the present worth of the revenue requirements. Present worth factors are calculated using the overall incremental cost of capital as the discount rate. The revenue requirement in each year is discounted back to the time of the original investment and a sum is computed. The engineer has thus determined the total present worth cost of an investment.

B. The Economist's Approach

Having calculated the present worth of revenue requirements for the plant over its full life, the next question is, what is the cost of having the plant for a year? From this cost, we develop carrying charges to be used in our marginal cost study. The annual revenue requirements, based on the engineer's simulation of the regulatory process, constantly decline over time. In the case of a plant that is maintained at full output, there is something wrong with loading all the costs into the early years. Computing marginal costs based upon the first year or several years of the engineer's revenue requirements would overstate the marginal cost of the facility.

For the purpose of marginal cost studies, we have, in the past, taken into account the full revenue requirement over the life of the plant and converted the nonuniform cash flow into a uniform annual series which is commonly called a levelized annual carrying charge. This is essentially equivalent to the mortgage formula, by which equal annual payments are charged on long-term secured loans. The levelized charge over the life of the facility will, of course, yield the same discounted value as the present worth of the revenue requirements. From the standpoint of equity, it should be emphasized that, if a plant is maintained at full output and if there is no inflation or technical change, the levelized annual carrying charge, in essence, assesses an equal real dollar cost to an equal physical output over the life of the plant. This concept appeals to those who see one purpose of regulation as determining rates that simulate activity in the competitive marketplace. For in the competitive marketplace, in times of no inflation or technical progress, the price for the same output would not vary depending upon the age of the facility, but would be set by market forces and, theoretically, would be stable over the life of the facility.

The levelized annual carrying charge is determined by dividing the present value of the revenue requirements by the present value of the mean annual surviving investment. This is shown on the bottom of page 2 of Table 15. The levelized annual carrying charge could also be developed by plugging the present value of revenue requirements and a rate of inflation net of technical progress of zero into the economist's formula that we will describe later.

In sum, the levelized annual carrying charge has the benefit of, over time, charging equal real dollar costs for the same service in times of no inflation or technical progress and simulating the price set by sellers in a competitive marketplace. This latter concept is especially important in the context of a marginal cost study. For, if marginal cost-based rates were to be put into effect, consideration would have to be given to the way goods are priced in the competitive market.[28] The bases for calculating electricity marginal costs would have to be comparable to the bases upon which all those competing for the electric utility dollar are setting their prices. This leads us to ask, what have we not discussed here that businessmen take into consideration?

The levelized annual carrying charge will only simulate market conditions when inflation and technical progress have a net rate of zero. It is a truism to state that, unfortunately, the economy is not in such a condition now, nor is there any well-supported view that it will return to such a condition in the visible future. Indeed, in the computation of the levelized charge, above described, we have already built in, in using current costs of capital, the market's assumption that inflation will continue. This is certainly one of the factors which has forced up permissible rates of return, based on the current cost of capital, from the long-persisting level of 6 to 7 percent to a figure some 50 percent higher. Consequently, as we noted in Topic 1.3, the levelized rate already recognizes inflation in the rate-of-return element but not in the depreciation element--an inconsistent treatment.

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[28] The framework behind the use of marginal cost pricing for electricity services is the efficient allocation of resources. Economic theory tells us, however, that pricing only one of many goods at marginal cost does not necessarily lead to the efficient allocation of resources. Since we have no control over the way other goods are priced, the solution, which will lead toward a more efficient allocation of resources, is to compute costs for all goods in a similar manner.

In light of this, what are the factors which we must consider? In the first place, as to technological progress, we are well aware that the days of "giant steps forward" for the utility industry seem to be behind us and that progress for the future will more likely be at a much slower rate. We are also aware of the fact that, for a variety of reasons (too lengthy to discuss here), we seem to have departed from the plateau of yesteryear, which in earlier decades produced an annual rate of inflation of less than one percent, and in the two post-war decades kept the rate to some 2 percent plus. Perhaps the circumstances of the immediate past decade will not be repeated and we will be returning to a materially lower figure in the future (though the capital market shows no sign of forecasting this); but, at the moment, in the politico-economic situation in which the world seems to find itself, few make such a sanguine forecast. We would therefore have to consider, based on the market's present evaluation of likely "steady state" inflation and the general consensus of informed views, that our factor "inflation net of technical progress" would have to be stated at somewhere between zero and 5 percent. This factor must be taken into consideration in computing the annual cost of capital investments in the same manner as would the marketplace when computing costs on which rates should be based.

In seeking to determine the cash flows that will result from an investment, businessmen are extremely cognizant of the effects of inflation and technical progress. In times of inflation, businessmen recognize that entry into the market at a later date will be more expensive and the market price will rise nearly to the cost of entry. Similarly, technical progress will lower the cost of entering the market and bring the market price down again to a level near the cost of entry. If the businessman expects inflation, he will forecast a rising series of cash flows. The expectations of this rising series of cash flows will force the current market price down below a levelized value. Conversely, if the businessman expects technical progress, he will forecast a declining series of cash flows. If he is to justify his investment on the basis of a discounted cash flow, he will expect a current price higher than the levelized value. Essentially, the market price will depend upon future expectations of inflation and technical progress.

The marginal cost of having a facility for a year, if computed for utilities in the same manner as for competing goods and services, must recognize the rate of inflation or technical progress in electric utility facilities. While it is never easy or even possible to peg an exact rate of inflation or technical progress, it must be recognized that those competing for the utility dollar are constantly forecasting these effects on prices. During times of slight inflation or technical progress, the distortion caused by assuming a net rate of zero and utilizing a levelized charge would be of minor concern. However, in the face of apparent inflation, it would be misleading to use the levelized charge and default to the assumption of a zero rate of inflation net of technical progress simply because we cannot precisely forecast the rate.

We have developed a formulation that will spread the discounted present value of the revenue requirements in a series that rises annually at the expected rate of inflation net of technical progress. This reflects the fact that, in the competitive market, prices would rise as the cost of entry rose.[29] It should be emphasized that this rate of inflation should, if possible, be specific to the type of investment so as to capture the effect of relative price changes. The rate must also be the long-term rate expected over the life of the investment. Using the rate of inflation net of technical progress which has been developed by a given utility would have the virtue of being consistent with the utility's carefully considered planning decisions.

In Table 16, we show the computation of such a carrying charge for use in the marginal cost study. This charge is based upon the formula described above and is also shown on the table. The basic input to the computation is the present value of all revenue requirements as computed in Table 15. The life of the investment, the time over which the total

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[29] We recognize that price is a complex function of supply and demand and will not attempt to develop a generalized price theory here. Suffice it to say that, for all practical purposes, entry cost and price can be assumed to move in the same direction.

present value of revenue requirments will be payed back, is, as in Table 15, 25 years. Computations are shown for long-term inflation rates net of technical progress of 2 and 4 percent annually. The annual charge according to the formula rises at the rate of inflation. In such a stream, the first year's carrying charge (used in the marginal cost calculation) represents the present-day dollar cost of having the facility for a year. This charge is converted to a percentage basis by dividing by $1,000--the original cost of the investment hypothesized in Table 15. We would leave to an actual presentation, in the light of the specific facts of the case, the determination of the rate of inflation net of technical progress which should be used in the computation. However, it can safely be said that the annualization factor so arrived at will likely be somewhat lower than the annualization factor (levelized) formerly employed.

This figure represents the quantification of the appropriate theoretical calculation of "economic depreciation" discussed in Topic 1.3, Section IV-F. It is not completely consistent with certain real world factors that appear to affect price formation in many competitive markets. In particular, predictions of the rate of inflation and technical progress become more and more uncertain as we go further out into the future. Either because of risk aversion or because of an inability to fully diversify such risks or other market imperfections, firms appear to give even greater relative weight to early periods than would be implied by the discount rate used in the above calculation. From the businessman's perspective, this appears as a shorter target payback period than would be implied by the discount rate used in the above calculation. Since these factors influence investment and pricing behavior by firms producing goods and services that are substitutes and complements for electricity, we believe that such considerations must also be factored into our attempt to simulate the effective competitive carrying charge used to calculate the marginal costs on which electricity prices will be based.

This shortened period, although it differs for every corporation and type of equipment, can be thought of as the lower limit of the asset depreciation accelerated tax lives allowed by the Internal Revenue Service. To compute marginal costs that more accurately reflect what competitors are doing, we can change the time period over which to recover the present value of the revenue requirements from the book life of the project to the tax life described above. Using the same formula, we show on Table 17 the charge based on the series which rises over the tax life of the project at the rate of inflation and yields the discounted present value of revenue requirements as calculated by the traditional engineer's approach. Since our sample investment represents a combustion turbine, the tax life is 16 years. Other than the change in the time period over which revenue is recovered, the computations on Tables 16 and 17 are identical.

It must be emphasized that the concepts discussed here are based on the theory outlined in Topic 1.3, Section IV-F and Attachment C. Readers should address themselves to those writings before turning to this section, in which the purpose is to apply "state of the art" measurement techniques to theoretical solutions. As a practical matter, we have developed a measurement tool which yields the theoretical solution sought in Topic 1.3 and another measurement tool that attempts to simulate, in a simple way, capital asset pricing decisions of businessmen. Recently, we have been making more extensive use of the latter measurement. At the option of the ratemaker, both measurements should be supplied. The theoretical basis in this area is quite firm. To quote from Topic 1.3, page 92:

> If technical progress is expected, the rental cost for this year is raised. It is raised because by buying this year rather than next, a certain price reduction is foregone. The foregone price reduction is part of this year's cost. By parallel reasoning, if inflation is expected, the rental cost of this year is reduced. Buying the machine this year rather than next has at least saved the higher price which will be demanded next year.

The process of developing measurements proper for application to marginal cost-based rates is still ongoing. While the methodologies outlined above are movements in the right direction, further refinements may be expected.

Further emphasis should be given to the fact that we are not recommending that the industry suddenly convert to this type of analysis to value plant and determine overall revenue requirements. We do believe, however, that to make the marginal costs and prices of electricity consistent with those arising in the marketplace in general, an economic approach to calculating the carrying charge, such as that described above, must be utilized. We do recognize that calculations based on this approach are quite sensitive to assumptions about the rate of inflation, technological change and the appropriate payback period to the extent that they differ from those implied by the cost of capital above. Since capacity costs are such a large proportion of total costs, the specific calculation utilized will have to be examined on a case-by-case basis, although the basic approach will remain unchanged.

X. MARGINAL LOSSES

Electric utility systems are not 100 percent efficient. Each increment of load on the system gives rise to an incremental energy loss. The further downstream from the generator that load is taken, the greater the loss. This means that the total input to the system must be greater than the sum of all loads measured at the point of consumption. It also means that each component of the system must be sized to accommodate the loads and losses of downstream system elements, as well as its own loads and losses.

Losses can be broadly classified as copper losses, core losses and dielectric losses. They are caused, respectively, by the production of heat, the establishment of magnetic fields and the leakage of current. The first of these will vary in proportion to the square of the load, while the latter two are fixed losses associated with specific equipment.

Many utilities conduct periodic studies of system losses. Such studies are generally conducted in either of two ways: one, by a simulation technique in which system load flows at the time of system peak are superimposed upon a model of the system and differences between inputs and outputs on each component are taken as the losses; or, two, by computational techniques. A common computational approach is to inventory the system in regard to fixed loss characteristics and subtract the sum of annual fixed losses from the total annual

(Load factor will change w/ levels.)

difference between system sales and system output in order to obtain total annual variable losses. The annual variable losses, expressed as a percentage of sales, are then divided by the annual load factor to derive variable losses at system peak, expressed as a percentage of peak demand.[30] Suffice it to say that a loss study can be made using accepted electrical engineering theory.

A. Capacity-Related Losses

The expansion of the capacity of both the transmission system and the distribution system is proportional to the diversified maximum demands of the consumers served from the various elements of the system. Hence, we can think of capacity-related losses as the losses that will occur after adjusting the system to meet a new load level. Therefore, the relevant losses are the average losses at the time of system peak demand. Average losses at system peak equal the ratio of input to output on each element of the system. Working upstream from the customer's service, it can be seen that losses on the low voltage secondary (S) become a part of the load on the transformer (T) and that part of the load on the high voltage primary (P) consists of the compounded losses on the other two elements. Thus, losses, and their

1 hour period of time

[30] A comprehensive discussion of losses can be found in Electric Utility Engineers of the Westinghouse Electric Corporation, Electric Utility Engineering Reference Book, Distribution Systems, Vol. 3 (East Pittsburgh, Pennsylvania: Westinghouse Electric Corporation, 1959).

effect on upstream capacity requirements, can be said to be cumulative. The following table serves to illustrate the point.

	Loss Factor	
Element	Simple	Cumulative
Secondary	S	S✓
Transformer	T	SxT✓
Primary	P	SxTxP✓

This cumulative characteristic of capacity-related losses (indeed, as we shall soon see, of all losses) makes it convenient to construct tables of so-called "capacity adjustment" factors to tell us how much additional capacity must be supplied in each system element upstream of the point at which service is taken.

Table 18 provides a numerical example of the development of capacity adjustment factors starting with annual variable losses by voltage level.[31] The annual variable losses are computed as a percentage of annual sales and this percentage is divided by the system load factor to obtain the average percentage variable losses at system peak. The computational notion here is the conversion of average annual variable losses to peak losses; hence, the use of system load factor as a divisor. The losses so computed are then accumulated upstream from the point of service. The effect of

[31] Actually, the capacity adjustment factor must account for both fixed and variable losses. We have included only variable losses in our illustration.

losses on costs can be seen quite clearly by comparing the capacity adjustment factors at the generator for service from the secondary (1.1477) and for service from the sub-transmission (1.0427). This means that, for every kilowatt of load on the secondary, some 15 percent additional generating capacity is required, while for service from the sub-transmission, only some 4 percent additional generating capacity is required. Putting this in dollars (at $100 per Kw), a secondary kilowatt costs $115 at the generator, while a sub-transmission kilowatt costs only $104 at the same point.

B. Energy-Related Losses

The difference between capacity-related losses and energy-related losses is that the former are based on an expanding system and the latter are based on the concept of additional energy supplied from a fixed system. Therefore, it is the change in input with respect to a change in output,

$$\frac{dKwh\ Input}{dKwh\ Output}$$

which is relevant with regard to energy-related losses. This, of course, is a marginal loss as defined in textbook terms.

Based on electric circuit theory, input and output can be expressed in terms of voltage, circuit resistance and load resistance. The change in input and output can then be derived with respect to a change in load (load resistance) and is expressed as:

$$\frac{dKwh\ Input}{dKwh\ Output} = 1 + 2\,\frac{Losses}{Load-Losses}$$

Rearranging these terms, the marginal energy adjustment factor can be expressed as:

$$\frac{dKwh\ Input}{dKwh\ Output} = 1 + \frac{2\ (A \times B)}{1-(A \times B)} \quad 1 + 2\frac{1}{\frac{1}{(A \times B)} - 1}$$

where:

A = variable peak losses as a percent of peak load;

and

B = load as a percent of peak load.

Therefore, the marginal loss factor depends upon the level of demand. This means that, in addition to deriving energy adjustment factors for each element of the system from which service is taken, we must also derive energy adjustment factors for each separate pricing period during which a different load level is expected to pertain. The appropriate load level is the average load during the period.

Table 19 contains a numerical example of this process.

XI. SUMMARIZING THE COSTS

We have described in previous sections how to compute the various components of the marginal cost of supplying electricity. The next step is to put these costs together in a format suitable to the ratemaker. All capacity costs have been expressed in terms of dollars per kilowatt. These costs can then be allocated to costing periods as described below. They should be adjusted to allow for losses at time of system peak as explained in Section X. Weighted average energy costs by costing period should be expressed in cents per kilowatt-hour and should include an adjustment for marginal energy losses. In this section, we will describe how to convert all raw capacity costs into a charge suitable for use in ratemaking, how to allocate these costs to costing periods and how to prepare a summary schedule for the ratemaker. Sample calculations and tables will be shown. We will also discuss some factors that the ratemaker should consider when converting these costs into rates.

A. Computing Marginal Capacity and Customer Costs

Marginal per-kilowatt costs have been developed for generation, transmission and distribution. If appropriate, separate distribution costs have been calculated for service from the various voltage levels. Similarly, a customer-related investment per customer has been calculated. These capacity- and customer-related costs can be converted to a format suitable to the ratemaker by use of the carrying charge. Additionally, capacity-related O&M expenses and a working capital revenue requirement should be allowed for.

On Table 20, we show the development of total unit marginal demand-related costs for each function. Each of the marginal unit investments per kilowatt was adjusted upwards by a general plant loading factor. This accounts for peripheral incremental capital investment, such as expanded office facilities and transportation equipment, that is necessary to provide service but which is not included in the incremental unit investments which we have calculated. The resulting figure is multiplied by the annual economic charge percentage to yield the annualized plant cost. To this cost the demand-related operation and maintenance expense is added. The demand-related transmission and distribution O&M expenses have been previously discussed and sample computations shown in Sections VI and VII, respectively. The generation demand-related O&M expense is described in the discussion of marginal energy costs. It is the portion of generation O&M expenses that rises with the rate of use of plant and, depending upon operational characteristics, will vary from utility to utility.

The revenue requirement for working capital must also be accounted for. Working capital includes prepayments, materials and supplies, and cash working capital (calculated as one-eighth of operating expenses). The revenue requirement for working capital is computed by multiplying the income tax adjusted rate of return by total working capital. The sum of plant-related O&M expenses, the annualized plant cost and the revenue requirement for working capital is the marginal capacity cost per kilowatt for each function.

The annual costs of customer-related facilities are derived on Table 21 in a manner similar to that described for Table 20. The general plant loading factor described above was applied, and the investment was multiplied by the annual economic charge percentage. Customer-related distribution O&M expenses, customer accounts and sales expenses and the revenue requirements for customer-related working capital (calculated as described above) were added to the annual plant cost to obtain the annual customer cost per customer.

The capacity-related costs must be adjusted for losses at time of peak. This concept and the methodology are explained in detail in the section on marginal losses.

B. Allocating Costs to Costing Periods

The annualized demand- or capacity-related costs, although expressed in dollars per kilowatt of system peak demand, are actually attributable to, in varying degrees, the demands during each hour of the year. In a purely theoretical sense, there are 8,760 costing periods in a year for capacity-related costs. For pragmatic reasons, we select costing and pricing periods. Section IV explains the rationale behind and the methodology for the selection of such periods. After selecting periods, costs are allocated to these periods based on the relative probability of shortage in each period. This concept is discussed in detail in Topic 1.3, pages 77 through 81.

The appropriateness of the use of shortage probabilities to allocate capacity costs to time periods has been extensively discussed both previously in this report and in Topic 1.3. This concept is new to most utility analysts, since implicit in the average cost ratemaking most familiar to utility analysts is the equal assignment of capacity costs to each hour. Remember, while capacity costs are most often assigned to classes based upon one of 29 accepted methods of cost allocation,[32] no allocation of costs is made to time periods. One of the basic prerequisites in explaining and understanding marginal cost methodology is to keep a clear distinction between the allocation of costs to time periods and the allocation of costs to classes.

Before proceeding, therefore, let us examine in more comprehensible terms the consequences of the recommendations of academic economists who tell us that capacity costs should be allocated to each hour of the year in relation to the relative probability of shortage in each hour. Why should we follow this recommendation when the primary determination of the <u>amount</u> of capacity is the peak load and the peak reserve requirement? For a moment, let us assume that we had an ideal pricing and communications system. We are able to transmit to each consumer the cost of a kilowatt over the next hour for each of the 8,760 hours in the year, and we let 8,760 consumption

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[32] See Attachment A of Topic 1.1.

decisions be made annually by each customer. Now assume that all consumers are economically rational, that is, they will not pay more for electricity than the cost of foregoing electricity usage. This cost can be measured for industrial or commercial customers in terms of foregone profit or (as an approximation of foregone profit) value added from ceasing to use electricity. For the residential customer, it will be measured chiefly in terms of the inconvenience of doing without lights or appliances.

If we were to accept the proposition that all capacity costs are attributable to the one peak hour, we would signal to the ratepayers for the expected peak hour the marginal fuel cost associated with a kilowatt consumed, as well as the entire annual marginal capacity cost of each kilowatt. Industry most likely would cease all production for that hour. Residential customers would turn off all appliances. The cost of shortage for any one hour is much less than the marginal annual cost of capacity allocated entirely to that one hour. Over the whole year, however, the expected marginal cost of shortage will equal the marginal cost of capacity. The expected marginal cost of shortage (over all hours of the year) is defined as the sum of the hourly probabilities of a shortage times the periodic marginal shortage costs. Due to the common load patterns of utilities, there are identifiable times of the year and times of the day when the probability of shortage is greater than at other times. Assuming the periodic cost of shortage to be constant,[33] each hour's relative contribution to the marginal annual capacity cost is determined by its relative shortage probability; hence, the economist's penchant for allocating capacity costs to time periods based upon relative loss-of-load probabilities.

Table 1, which was described in the section on the selection of costing and pricing periods, shows the development of capacity cost allocation factors based upon loss-of-load probabilities. The general form of the development of these factors is based on the equation:

$$\sum_{i=1}^{8,760} P_i d = C$$

where:

P_i = Loss-of-Load Probability in Period i
d = Periodic Shortage Cost
C = Expected Annual Cost of Shortage

From this, it follows that the expected marginal shortage or capacity cost can be allocated to any period by use of the following factor:

$$CAF = \frac{P_{cp}}{P_a}$$

where:

CAF = Costing Period Capacity Cost Allocation Factor
P_{cp} = Costing Period Loss-of-Load Probability
P_a = Annual Loss-of-Load Probability.

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[33] Allowing this cost to vary across periods does not change the nature of the results. See Topic 1.3, pp. 77-81.

This is explained in more detail in Topic 1.3, pages 77 and 81. Table 22 shows the allocation of costs to costing periods using these factors.[34] The costs per kilowatt of system peak adjusted for losses are multiplied by the costing period capacity cost allocation factor and divided by the ratio of seasonal mean peak demand to system peak demand. The resulting figure is a capacity cost per kilowatt of seasonal mean peak demand for each costing period.

The allocation of capacity costs to costing periods is an integral part of marginal costing methodology. The adjustment of costs from a cost per kilowatt of system peak demand to a cost per kilowatt of seasonal mean peak demand, however, is just a transitional step toward the ratemaking process. It accounts for the fact that seasonal mean peak demand is lower than system peak demand, and, if rates are to be based upon probable contribution to seasonal mean peak demand, costs computed per kilowatt of system peak demand must be adjusted upwards.

Capacity cost computations are made separately for generation, transmission, distribution and, if appropriate, each voltage level of the distribution system. This enables the

[34] These factors may not necessarily be the best measurement of the probability of shortage at the distribution level. Attachment A, pages A5-A6, offers an alternate method of allocating these costs to time periods.

ratemaker to choose the appropriate costs for each class of consumer and to turn the costs into rates based upon the correct billing determinants. Costs are also computed separately for service from each voltage level. The difference in costs for service from each voltage level simply reflects a difference in losses. For example (as shown in Table 18), at time of peak one kilowatt at a secondary customer's meter will require 1.1477 kilowatts of generating capacity, while one kilowatt at a primary customer's meter will require only 1.0853 kilowatts of generating capacity. The difference is losses on the secondary system.

C. Preparing the Summary Table

The final step is the preparation of the summary table and an explanation to the ratemaker of what the costs represent. The summary table should show for each costing period the capacity and energy costs. Costs for service from each voltage level are different and should be shown separately. Table 23 is the summary table that we would present to the ratemaker. The marginal energy costs for each costing period are adjusted for marginal energy losses, A&G expenses and a working capital allowance. These computations are shown on Table 24. They are per kilowatt-hour costs and are applicable to all kilowatt-hours consumed during the costing period. The capacity costs are the sum of the per-kilowatt costs of each function and are applicable to service from each voltage level. For example, the cost of service from the secondary entails the capacity cost of generation, transmission, sub-transmission, the primary distribution system and the secondary distribution system, all adjusted by loss factors for secondary service. The cost of service from sub-transmission includes the capacity cost of generation, transmission and sub-transmission, all adjusted by loss factors for service from sub-transmission. These capacity costs are expressed in cost per kilowatt of seasonal mean peak demand.

The ratemaker, therefore, now has a costing period kilowatt-hour energy cost which he can apply to periodic energy consumption. He also has a costing period capacity cost which he can apply to class contributions to seasonal mean peak demand. There is, however, one more important factor of which the ratemaker must be made aware. The distribution portion of the capacity costs, although expressed per kilowatt of seasonal mean peak demand, will have to be adjusted to reflect differing class capacity cost responsibilities for distribution investment. For in fact, planned investment in distribution capacity is causally related to the whole gamut of demand measurements, ranging from a customer's maximum demand to class peak demands to the maximum coincident demand placed upon the distribution system. Ideally, one would want to analyze the marginal distribution capacity cost separately for each segment of the distribution system and attribute the responsibility for this investment to classes based upon probable class contribution to the cost causative demands for each segment. Since information to permit such detailed analyses is often in practice not available, we have not provided an illustrative example. Instead, we leave it to the ratemaker and costing analyst (in specific cases) to make adjustments to the distribution capacity costs, in order to account (in a fashion based on load research or informed judgment) for the different distribution cost responsibilities of the classes.

With capacity and energy costs in hand, the ratemaker needs only customer costs. These costs are shown on Table 25 and are expressed in dollars per customer per year. These costs are not time-differentiated and should be divided equally over each billing period.

These summary tables provide all the costing information necessary to develop marginal cost-based rates. The method of developing these rates and other considerations of the ratemaker are discussed in Topic 5.

USE OF LOSS-OF-LOAD PROBABILITIES

The computation set forth below is undoubtedly a familiar one to most utility planners. It is understood that it is naive in its simplicity. However, that fact notwithstanding, it does express the probability that a generator will be forced out of service at any given time and, based on a utility's maintenance schedule, can be expected to produce with sufficient accuracy for ratemaking purposes the pattern of relative probabilities (throughout a time period) that load will exceed capacity. It is a computation that can be made by personnel of a utility that does not, as a matter of course, include such computations in its planning process. We assume (for our purposes) that production and transmission facilities are generally planned in conjunction with each other and, thus, it will be appropriate to use the same probability measure for allocating both kinds of capacity-related costs to periods.

We deal with a very simple system having three machines available. Each has the same capacity and the same forced outage rate.

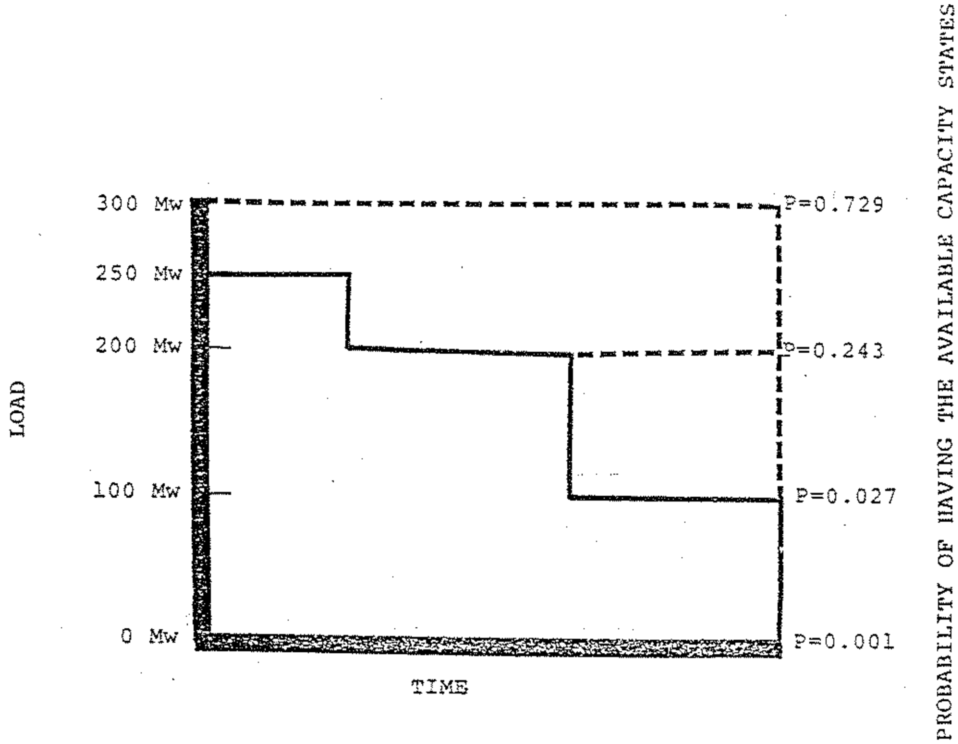
Machine	A	B	C
Capacity	100 Mw	100 Mw	100 Mw
Forced Outage Rate	0.1	0.1	0.1

There are eight possible combinations of A, B and C either working or not.

State		Probability
In	Out	
ABC	-	0.9 x 0.9 x 0.9 = 0.729 of having 300 Mw
AB AC BC	C B A	0.9 x 0.9 x 0.1 + 0.9 x 0.1 x 0.9 + 0.1 x 0.9 x 0.9 = 0.243 of having 200 Mw
A B C	BC AC AB	0.9 x 0.1 x 0.1 + 0.1 x 0.9 x 0.1 + 0.1 x 0.1 x 0.9 = 0.027 of having 100 Mw
-	ABC	0.1 x 0.1 x 0.1 = 0.001 of having 0 Mw
		1.000

With n machines, there are 2^n possible combinations, which means that when the number of machines gets beyond, say, five or six, one would wish to enlist the aid of the computer department.

If we superimpose the probabilities of having the amounts of capacity available on a load duration curve, we can derive the probability that load will exceed capacity at various load levels.



For loads between 200-300 Mw, there is 1 - 0.729 = 0.271 probability of insufficient capacity.
For loads between 100-200 Mw, there is 1 - (0.729 + 0.243)= 0.028 probability of insufficient capacity.
For loads between 0-100 Mw, there is 0.001 probability of insufficient capacity.

Let us see what the results of this simple computation tell us with regard to the allocation of capacity-related costs to costing/pricing periods. It can be seen that the light-load (off-peak) period has a probability of load exceeding capacity equal to 1/270 of the same probability during the peak-load period and that the probability during the shoulder period is some 1/10 of the probability during the peak-load period. Using the methodology set forth in Topic 1.3[1]

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[1] See pages 63 to 67.

assuming first that marginal capacity cost is $28 per Kw, and, second, that each of the periods described has (for simplicity) an equal number of hours, we can compute the allocated capacity costs as follows:

Period	P	Relative P	Relative P x $28
Peak	0.271	0.903	$25.28
Shoulder	0.028	0.093	2.60
Off-Peak	0.001	0.004	.12
	0.300	1.000	28.60

If each of the periods contains 2920 hours (8760 ÷ 3), the capacity-related component of the kilowatt-hour cost in each period is:

Peak	0.866¢
Shoulder	0.089¢
Off-Peak	0.000¢

We would conclude that the capacity-related cost for off-peak consumption is virtually zero and would not allocate such costs to that period. When would one consider including capacity costs in the off-peak period? A simple rule-of-thumb we have used says, that when the total cost per kilowatt-hour would not be changed in the second decimal place, no capacity-related cost should be allocated to the period.

With regard to the peak and shoulder periods, it is the relationship between their costs that poses the most interesting question in the light of our earlier recommendation that diurnal peak periods initially be set in a very broad manner. That recommendation seems to violate the concept (expressed in an earlier section of this report) that hours of relatively homogeneous costs should be grouped into common cost/price periods. However, when we consider all aspects of the problem, we will be able to see that this concept has not been violated. Earlier in this section, reference was made to load shifting possiblities when peak periods were priced high in relation to hours immediately adjacent (shoulders). These shoulder hours, therefore, have a high probability of becoming peak hours because of the price differential. If we apply the reasoning in Section III of this report regarding iteration towards equilibrium between supply and demand, we can see that while it may not be precisely correct to price some shoulder hours as though they were peak hours, it is (in the absence of knowledge as to cross-elasticities between hours of use) practically as close to the conceptual solution as we can get.

It is recognized that on some electric utility systems, the peak loads on the distribution system will not coincide with the peak loads on generation and transmission. Additionally, even where these two peaks are coincident, the various components of the distribution system are not necessarily experiencing their individual peaks. It is possible that this situation will pertain on both a seasonal and a diurnal basis.

In what follows, we will set forth a procedure for computing relative probabilities that load will exceed capacity on the distribution system. This procedure considers the distribution system in aggregate and assumes in so doing that the contingency plan of the system provides the thermal capacity to serve the load under contingency conditions. As a result, the procedure assumes that the capacity exists and sets out to determine the relative probability that any time period will be the peak. The procedure is set forth in terms of distribution substations but can be applied to any class of equipment.

1. Record the monthly peak load for each substation.
2. Adjust the monthly peak loads for each substation to account for seasonal differences in thermal capability (e.g., if the summer capability is 80 percent of the winter capability, divide each summer monthly peak load by 0.8).
3. Subtract each station's adjusted monthly peak load from its adjusted annual peak load.
4. Sum the differences of all stations in each month.
5. Take the reciprocal of the summation of monthly differences.
6. Total the reciprocals and take each month's reciprocal as a percentage of the total.
7. Use the resulting percentages as period allocation factors.

TABLE 1

CALCULATION OF RELATIVE MEAN VALUE OF LOSS-OF-LOAD PROBABILITIES BY COSTING PERIOD

Costing Period	LOLP[1] -(Days	Mean LOLP in Period per Year)-	Mean LOLP ÷ Σ Mean LOLP	Relative Value of LOLP
	(1)	(2)	(3)	(4)
Winter				
October	1.401			
November	3.690			
December	3.382			
January	0.849			
February	2.487			
March	1.176			
	12.985	2.164	0.872	0.87
Base Running				
April	0.459			
May	0.113			
June	0.338			
July	0.227			
August	0.274			
September	0.503			
	1.914	0.319	0.128	0.13

[1] Ten-year average of Company loss-of-load probabilities.

Source: Based on Company-supplied data.

TABLE 2

MARGINAL RUNNING COSTS
BY COSTING PERIOD

Year	Peak Hours Summer (1)	Peak Hours Winter (2)	Peak Hours Base (3)	Off-Peak Hours Summer (4)	Off-Peak Hours Winter (5)	Off-Peak Hours Base (6)
Weighted Average Running Costs in Current Dollars[1]						
1976	-	1.89¢	1.71¢	-	0.64¢	0.86¢
1977	-	2.48	2.12	-	1.06	0.98
1978	-	1.53	1.47	-	0.85	0.78
1979	-	2.05	1.77	-	1.05	0.93
1980	-	2.66	1.88	-	1.13	0.92
1981	-	2.64	1.90	-	1.21	1.05
1982	-	3.24	2.33	-	1.13	1.21
Annual Deflation Factor[2]						
1976	-	1.0000	1.0000	-	1.0000	1.0000
1977	-	1.0500	1.0500	-	1.0500	1.0500
1978	-	1.1025	1.1025	-	1.1025	1.1025
1979	-	1.1576	1.1576	-	1.1576	1.1576
1980	-	1.2155	1.2155	-	1.2155	1.2155
1981	-	1.2763	1.2763	-	1.2763	1.2763
1982	-	1.3401	1.3401	-	1.3401	1.3401
Weighted Average Running Cost in Constant 1976 Dollars[1]						
1976	-	1.89¢	1.71¢	-	0.64¢	0.86¢
1977	-	2.36	2.02	-	1.01	0.93
1978	-	1.39	1.33	-	0.77	0.71
1979	-	1.77	1.53	-	0.91	0.80
1980	-	2.19	1.55	-	0.93	0.76
1981	-	2.07	1.49	-	0.95	0.82
1982	-	2.42	1.74	-	0.84	0.90
Period Weighted Average		2.02	1.64		0.81[3]	

Note: In this case the appropriate costing seasons are a winter season and a base season consisting of all other months. Other companies may have different seasonal divisions. For illustrative purposes three seasons have been displayed on this table. Marginal running costs, however, have only been calculated for the appropriate costing seasons.

[1] Running costs are expressed in cents per kilowatt-hour and include fuel and variable power production O&M expenses.
[2] Based on forecast 5 percent general inflation.
[3] Weighted average of off-peak winter and base running costs.

TABLE 3

MARGINAL INVESTMENT IN TRANSMISSION FACILITIES PER ADDED KILOWATT OF SYSTEM PEAK DEMAND

	Gross Additions to Transmission Plant in Service (Thousand 1975 Dollars)	Additions to System Peak Load (Mw)
	(1)	(2)
Actual		
1971	$ 40,000	300
1972	99,000	410
1973	62,000	530
1974	38,000	400
1975	50,000	505
Projected		
1976	$ 70,000	525
1977	60,000	595
1978	58,000	680
1979	96,000	740
1980	90,000	800
1981	69,000	900
1982	85,000	975
1983	92,000	1,000
Additions 1971-1975	$289,000	2,145
Marginal Transmission Investment per Added Kilowatt of System Peak 1971-1975	$134.73/Kw	
Additions 1976-1983	$620,000	6,215
Marginal Transmission Investment per Added Kilowatt of System Peak 1976-1983	$ 99.76/Kw	
Additions 1971-1983	$909,000	8,360
Marginal Transmission Investment per Added Kilowatt of System Peak 1971-1983	$108.73/Kw	

MARGINAL INVESTMENT IN TRANSMISSION FACILITIES PER ADDED KILOWATT OF SYSTEM PEAK DEMAND

	Gross Additions to Transmission Plant in Service	Additions Related to Remote Generation	Additions Related Solely to Pool Requirements	Additions Related to Load Added After Period	Load-Related Additions to Transmission Plant in Service	Additions to System Peak (Mw)
	(Thousand 1976 Dollars)					
	(1)	(2)	(3)	(4)	(1)-[(2)+(3)+(4)] (5)	(6)
Actual						
1971	$40,000	$ 4,000	-	-	$ 36,000	300
1972	99,000	40,000	-	-	59,000	410
1973	62,000	22,000	-	-	40,000	530
1974	38,000	-	-	-	38,000	400
1975	50,000	-	$5,000	-	45,000	505
Projected						
1976	$70,000	-	$4,000	-	$ 66,000	525
1977	60,000	-	-	-	60,000	595
1978	58,000	$ 6,000	-	-	52,000	680
1979	96,000	27,000	-	-	69,000	740
1980	90,000	23,000	3,000	-	64,000	800
1981	69,000	-	2,000	-	67,000	900
1982	85,000	-	-	$6,000	79,000	975
1983	92,000	-	-	8,000	84,000	1,000
Additions, 1971-1975					$218,000	2,145
Marginal Transmission Investment per Added Kilowatt of System Peak, 1971-1975					$101.63/Kw	
Additions, 1976-1983					$541,000	6,215
Marginal Transmission Investment per Added Kilowatt of System Peak, 1976-1983					$87.05/Kw	
Additions, 1971-1983					$759,000	8,360
Marginal Transmission Investment per Added Kilowatt of System Peak, 1971-1983				Used in Study	$90.79/Kw	

TRANSMISSION EXPENSE PER KILOWATT OF SYSTEM PEAK DEMAND

Year	Transmission Operation and Maintenance Expense	Leased Rentals	Transmission Operation and Maintenance Expense Less Leased Rentals	System Peak Demand (Mw)	Expense per Kw of System Peak Demand	Cost Index	Expense per Kw of System Peak Demand (1975 Dollars)
	(Thousand Dollars)	(Thousand Dollars)	(Thousand Dollars)				
	(1)	(2)	(1)-(2) (3)	(4)	(3)÷(4) (5)	(6)	[(5)÷(6)]x100 (7)
Actual							
1970	$ 5,770	$190	$ 5,580	6,300	$0.89	71	$1.25
1971	5,830	180	5,650	6,600	0.86	76	1.13
1972	6,800	200	6,600	7,500	0.88	81	1.09
1973	7,650	200	7,450	8,300	0.90	87	1.03
1974	9,900	200	9,700	8,000	1.21	93	1.30
1975	10,200	250	9,950	8,400	1.18	100	1.18
Projected							
1976	$10,850	$250	$10,600	8,820	$1.20	107	$1.12
1977	11,850	350	11,500	9,350	1.23	114	1.08
1978	12,550	350	12,200	9,700	1.26	123	1.02
1979	13,900	200	13,700	10,300	1.33	131	1.02
1980	15,100	0	15,100	10,600	1.42	140	1.01
1981	16,000	0	16,000	10,950	1.46	150	0.97
Estimated Transmission O&M Expense per Kilowatt for Planning Period (1975 Dollars)							$1.02

DERIVATION OF INVESTMENT PER CUSTOMER
FOR A MINIMUM DISTRIBUTION SYSTEM

	Quantity (1)	Unit Cost (1975 Dollars) (2)	Total Cost (Thousand 1975 Dollars) (1)x(2) (3)	Customers Served (4)	Cost per Customer (Dollars) (3)÷(4) (5)
(1) Land and Land Rights	-	-	-	-	$ 19
(2) Poles, Towers and Fixtures					
a. Primary	564,039 poles	$170.00/pole	$95,887	902,000	106
b. Secondary	221,300 poles	$125.00/pole	-	-	-
(3) Overhead Conductors and Devices[1]					
a. Primary Conductors	38,488 miles	$985/mile	37,911	902,000	42
b. Primary Devices	-	-	-	-	4
c. Secondary	30,987 miles	$985/mile	30,522	902,000	34
(4) Line Transformers[1]	268,400 trans.	$165/trans.	44,286	902,000	49
(5) Services	747,860 services	$121/service	90,491	902,000	100
(6) Meters	-	-	-	-	25
(7) Total Customer Cost for a Primary Customer (1)+(2a)+(3a)+(3b)+(5)+(6)					-
(8) Total Customer Cost for a Secondary Customer (1)+(2)+(3)+(4)+(5)+(6)					$379

Note: In this case all customers are served at secondary voltage. If there were primary customers, a primary customer cost would have been computed as shown in line (7).

[1] Includes installation (labor) costs only.

DERIVATION OF MARGINAL DEMAND-RELATED DISTRIBUTION INVESTMENT

Year	Distribution Peak (Mw)	Demand-Related Distribution Plant (Thousand 1975 Dollars)
	(1)	(2)
1958	1,172	574,498
1959	1,415	392,960
1960	1,451	618,431
1961	1,581	636,875
1962	1,617	663,879
1963	1,702	728,048
1964	1,835	748,480
1965	1,903	774,616
1966	2,051	800,464
1967	2,049	819,524
1968	2,320	837,668
1969	2,422	861,738
1970	2,347	887,403
1971	2,573	909,464
1972	2,624	935,005
1973	2,740	962,905
1974	2,658	989,165

Results

$$DP = \underset{(9.727)}{245{,}700{,}000} + \underset{(21.925)}{265.94}(X_1)$$

Where DP = Distribution Plant in Service
X_1 = Distribution Peak Demand in kilowatts

$\bar{R}^2 = .967722$

Durbin Watson = 1.691

Note: Numbers in parentheses are the t-ratios.

TABLE 8

DERIVATION OF MARGINAL DEMAND-RELATED DISTRIBUTION INVESTMENT

Year	Additions to Distribution Plant (Thousand 1975 Dollars) (1)	Additions for Replacement of Existing Equipment (Thousand 1975 Dollars) (2)	Additional Customers at Year End (3)	Customer-Related Additions to Plant (Thousand 1975 Dollars) (3)x\$379[1] (4)	Demand-Related Additions to Plant (Thousand 1975 Dollars) (1)-(2)-(4) (5)	Additions to Distribution System Demand (Mw) (6)	Marginal Demand-Related Distribution Investment per Added Kilowatt of Distribution Demand (Dollars/Kw) (5)÷(6) (7)
1975	$ 49,875	$ 3,000					
1976	54,327	1,250					
1977	59,086	2,860					
1978	68,720	2,082					
1979	69,426	1,940					
1980	75,117	2,419					
Total	$376,551	$13,551	147,000	$55,713	$307,287	1,600	$192/Kw

[1] Table 6, line (8).

Year	Total Distribution Operation and Maintenance Expense[1] ---(Thousand	Customer-Related Expense Dollars)---	Number of Customers[2]	Customer-Related Expense per Customer	Demand-Related Expense (Thousand Dollars)	Peak Distribution Demand[3] (Mw)	Demand-Related Expense per Kw of Peak Distribution Demand	Electric Labor Cost Index[4] (1975=100)	Customer-Related Expense per Customer -------(1975	Demand-Related Expense per Kw of Peak Distribution Demand Dollars)-------
	(1)	(1)x60% (2)	(3)	(2)÷(3) (4)	(1)x40% (5)	(6)	(5)÷(6) (7)	(8)	[(4)÷(8)]x100 (9)	[(7)÷(8)]x100 (10)
1970	$ 7,186	$4,312	361,514	$11.93	$2,874	1,305	$2.20	72	$16.57	$3.06
1971	8,203	4,922	370,690	13.28	3,281	1,426	2.30	78	17.03	2.95
1972	8,851	5,311	380,657	13.95	3,540	1,547	2.29	82	17.01	2.79
1973	9,731	5,839	390,579	14.95	3,892	1,675	2.32	85	17.59	2.73
1974	10,376	6,226	397,429	15.67	4,150	1,583	2.62	92	17.03	2.85
Estimated Distribution O&M Expense for the Planning Period (1975 Dollars)									17.05[5]	2.25[6]

[1] Distribution expenses shown in Column (1) are total distribution O&M expenses less street lighting expenses and overheads allocated to street lighting expenses. Operation overheads (Accounts 580, 588 and 589) and maintenance overheads (Accounts 590 and 598) are allocated to street lighting expenses on the basis of the relative importance of these expenses in total operation and total maintenance expenses (excluding overheads), respectively. Distribution expenses are from FPC Form 1, pp. 418 and 419, annual issues.

[2] Average number of customers per month, excluding public street and highway lighting customers (from Uniform Statistical Report, p. E-14, annual issues), plus locked meters on customers' premises (from FPC Form 1, p. 447, annual issues).

[3] Peak distribution demand is estimated to be 95 percent of system peak demand.

[4] The electric labor cost indexes for 1970-1974 are from the Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 102. The Handy-Whitman electric labor cost indexes on a base of 1949=100 were converted to a July 1, 1975 base.

[5] The 1970-1974 average is used as the estimate of this expense for the planning period.

[6] Estimation is based on an analysis of the trend in demand-related expense.

TABLE 10

CUSTOMER ACCOUNTS EXPENSE PER WEIGHTED CUSTOMER

1970 - 1975

		1970 (1)	1971 (2)	1972 (3)	1973 (4)	1974 (5)	1975 (6)
(1)	Customer Accounts Expense (Thousand Dollars)	$7,505	$8,209	$9,329	$10,248	$12,778	$17,671
(2)	Customers[1]	950,967	986,139	1,026,415	1,069,286	1,099,055	1,116,246
(3)	Customer Accounts Expense per Customer (1) ÷ (2)	$7.89	$8.32	$9.09	$9.58	$11.63	$15.83
(4)	Customer Accounts Expense Weighting Factor[2]	1.01	1.01	1.01	1.01	1.01	1.01
(5)	Expense per Weighted Customer (3) ÷ (4)	$7.81	$8.24	$9.00	$9.49	$11.51	$15.67
(6)	Electric Labor Cost Index[3] (1975=100)	62	70	81	84	90	100
(7)	Expense per Weighted Customer in 1975 Dollars [(5) ÷ (6)]x100	$12.60	$11.77	$11.11	$11.30	$12.79	$15.67
(8)	Estimated Expense of the Planning Period			$14.23			

[1] Total average number of customers.
[2] Based upon customer accounts expenses on an account-by-account basis and average number of customers, both by class of service from Company's fully allocated cost study.
[3] The electric labor cost indexes for 1970-1975 are from the Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 102. The Handy-Whitman electric labor cost indexes on a base of 1949=100 were converted to a July 1, 1975 base.

Source: Line (1): FPC Form 1, p. 419, annual issues.
Line (2): FPC Form 1, p. 414, annual issues.

1970 - 1975

		1970	1971	1972	1973	1974	1975
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	Sales Expense (Thousand Dollars)	$3,903	$3,240	$2,993	$2,680	$2,438	$2,735
(2)	Customers[1]	950,976	986,139	1,026,415	1,069,286	1,099,055	1,116,246
(3)	Sales Expense per Customer (1)÷(2)	$4.10	$3.29	$2.92	$2.51	$2.22	$2.45
(4)	Sales Expense Weighting Factor[2]	3.5	3.5	3.5	3.5	3.5	3.5
(5)	Expense per Weighted Customer (3)÷(4)	$1.17	$0.94	$0.83	$0.72	$0.63	$0.70
(6)	Electric Labor Cost Index[3] (1975=100)	62	70	81	84	90	100
(7)	Expense per Weighted Customer in 1975 Dollars [(5)÷(6)]x100	$1.88	$1.34	$1.02	$0.86	$0.70	$0.44
(8)	Estimated Expense for the Planning Period			$0.70			

[1]Total average number of customers.

[2]Based upon sales expense and average number of customers, both by class of service from Company's fully allocated cost study.

[3]The electric labor cost indexes for 1970-1975 are from the Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 102. The Handy-Whitman electric labor cost indexes on a base of 1949=100 were converted to a July 1, 1975 base.

Source: Line (1): FPC Form 1, p. 419, annual issues.
Line (2): FPC Form 1, p. 414, annual issues.

TABLE

CUSTOMER ACCOUNTS EXPENSE BY CLASS OF SERVICE

	Weighting Factor[1] (1)	Customer Accounts Expense[2] (1)x$14.23[3] (2)
Residential	1.00	$14.23
Residential with Water Heating	1.00	$14.23
Residential--All Electric	1.00	$14.23
General	1.50	$21.35
General--All Electric	1.50	$21.35
Industrial	4.00	$56.92

[1] Based upon customer accounts expenses on an account-by-account basis and average number of customers, both by class of service from Company's fully allocated cost study.

[2] Customer accounts expense by class of service is the product of the weighting factor shown in Column (1) and the estimated customer accounts expense per weighted customer for the planning period.

[3] Table 10.

TABLE 12

SALES EXPENSE BY CLASS OF CUSTOMER

	Weighting Factor[1] (1)	Sales Expense[2] (1)x$0.70[3] (2)
Residential	1.00	$0.70
Residential with Water Heating	1.20	$0.84
Residential--All Electric	2.00	$1.40
General	1.00	$0.70
General--All Electric	2.00	$1.40
Industrial	10.00	$7.00

[1] Based upon sales expenses on an account-by-account basis and average number of customers, both by class of service from Company's fully allocated cost study.
[2] Sales expense by class of customer is the product of the weighting factor shown in Column (1) and the estimated sales expense per weighted customer for the planning period.
[3] Table 11.

COMPUTATION OF LOADING FACTORS FOR ADMINISTRATIVE AND GENERAL EXPENSES AND SOCIAL SECURITY AND UNEMPLOYMENT INSURANCE TAXES

1974

	FPC Account Number	Account	Amount (Thousand Dollars)
		Administrative and General Expenses and Social Security and Unemployment Insurance Taxes, 1974[1]	
		Applicable to Managerial Effort	
(1)	920	Administrative and General Salaries	$ 6,489
(2)	921	Office Supplies and Expenses	4,086
(3)	922	Administrative Expense Transferred--Credit	(171)
(4)	930	Miscellaneous General Expenses	3,718
(5)	931	Rents	41
(6)		Total	$14,163
(7)		Applicable to Energy-Related O&M Expenses[2]	$9,489
(8)		Applicable to Other O&M Expenses (6)-(7)	$4,674
		Applicable to Labor	
(9)	925	Injuries and Damages	$1,311
(10)	926	Employee Pensions and Benefits	4,815
(11)	929	Duplicate Charges--Credit	(581)
(12)	408.1	Social Security and Unemployment Insurance Taxes	3,048
(13)		Total	$8,593
(14)		Applicable to Energy-Related O&M Expenses[3]	$1,890
(15)		Applicable to Other O&M Expenses (13)-(14)	$6,703
		Applicable to Plant	
(16)	923	Outside Services Employed	$ 701
(17)	924	Property Insurance	723
(18)	927	Franchise Requirements	-
(19)	928	Regulatory Commission Expenses	49
(20)	932	Maintenance of General Plant	968
(21)		Total	$2,441
(22)		Total A&G Expenses and Social Security and Unemployment Insurance Taxes (6)+(13)+(21)	$25,197
(23)		Total A&G Expenses (22)-(21)	$22,149
(24)		Total Operation and Maintenance Expenses, 1974[4]	$178,253
(25)		Total O&M Expenses Excluding A&G Expenses (24)-(23)	$156,104
(26)		Fuel and Purchased Power[5]	$89,769
(27)		Energy-Related Production O&M Expenses Excluding Fuel and Purchased Power[6]	$14,794
(28)		Total Energy-Related O&M Expenses (26)+(27)	$104,563
(29)		Labor-Related O&M Expenses (25)-(28)	$51,541
(30)		A&G Loading Factor Applicable to Labor-Related O&M Expenses [(8)+(15)]÷(29)	22.07%
(31)		Total Gross Plant, December 31, 1974[7]	$1,248,763
(32)		A&G Loading Factor Applicable to Plant (21)÷(31)	0.20%
(33)		Electricity Generated and Purchased (Gwh)[4]	16,795
(34)		Energy-Related A&G Expenses (Mills/Kwh) [(7)+(14)]÷(33)	0.68

[1] A&G expenses (Accounts 920-932) are from FPC Form 1, 1974, p. 419, Social Security and unemployment insurance taxes (Account 408.1) are from *Ibid.*, p. 222 *et seq.*, col. (1).

[2] Total A&G expenses applicable to managerial effort have been allocated to energy-related O&M expenses on the basis of the ratio of total energy-related production O&M expenses [line (28)] to total O&M expenses excluding A&G expenses [line (25)].

[3] Total A&G expenses applicable to labor have been allocated to energy-related O&M expenses on the basis of the ratio of energy-related O&M production expenses excluding fuel and purchased power [line (27)] to total O&M expenses excluding fuel and purchased power and A&G expense [line (25)] minus [line (26)].

[4] FPC Form 1, 1974, p. 420.

[5] *Ibid.*, pp. 417-418.

[6] Energy-related production expenses were derived by the allocation of production O&M expenses, by account, as reported in FPC Form 1, pp. 417-418, to energy and demand using factors developed by NERA.

[7] *Ibid.*, p. 403.

[8] *Ibid.*, p. 431.

CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT

The sample computation of the present value of revenue requirements is based upon the following factors. The book life or average service life is 25 years. The retirement dispersion pattern is based upon an Iowa SQ mean annual survivors curve. The service life and survivor curve represent those typical of combustion turbine investment.

The overall incremental cost of capital is computed as follows:

Long Term Debt	50% x 9% =	4.50%
Preferred Stock	13% x 10% =	1.30%
Common Stock Equity	37% x 14% =	5.18%
		10.98%

The total return and income tax calculations reflect: (a) the normalization of the difference between book and double declining balance asset depreciation range (lower limit) (DDB/ADR) depreciation; and (b) the ratable flow through of the investment tax credit over book life. The investment tax credit rate is 4 percent. The lower limit tax depreciation life is 16 years.

Mean net investment (rate base) is the mean annual surviving investment less the book depreciation reserve and the deferred tax reserve. The combined federal and state income tax rate is 51.45 percent. The property tax rate is [illegible].9 percent of mean net book investment.

CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT

YEAR	MEAN ANNUAL SURVIVORS	BOOK DEPRE CIATION 4.000% * (1)	RETIRE MENTS	BOOK DEPRE CIATION RESERVE	MEAN NET BOOK INVEST MENT (1)-(4)	ADR DDB DEPRE CIATION	DEFERRED INCOME TAX 0.5145* (6)-(2)	DEFERRED TAX RESERVE	INVESTMENT TAX CREDIT: CREDIT	INVESTMENT TAX CREDIT: AMORTI ZATION	INVESTMENT TAX CREDIT: RESERVE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	1000	40.00	0	0.00	1000.00	125.00	43.73	0.00	40	1.60	0.00
2	1000	40.00	0	40.00	960.00	109.38	35.69	43.73	0	1.60	38.40
3	1000	40.00	0	80.00	920.00	95.70	28.66	79.43	0	1.60	36.80
4	1000	40.00	0	120.00	880.00	83.74	22.50	108.09	0	1.60	35.20
5	1000	40.00	0	160.00	840.00	73.27	17.12	130.59	0	1.60	33.60
6	1000	40.00	0	200.00	800.00	64.11	12.41	147.71	0	1.60	32.00
7	1000	40.00	0	240.00	760.00	56.10	8.28	160.11	0	1.60	30.40
8	1000	40.00	0	280.00	720.00	49.09	4.68	168.40	0	1.60	28.80
9	1000	40.00	0	320.00	680.00	49.09	4.68	173.07	0	1.60	27.20
10	1000	40.00	0	360.00	640.00	42.07	1.07	177.75	0	1.60	25.60
11	1000	40.00	0	400.00	600.00	42.07	1.07	178.82	0	1.60	24.00
12	1000	40.00	0	440.00	560.00	42.07	1.07	179.88	0	1.60	22.40
13	1000	40.00	0	480.00	520.00	42.07	1.07	180.95	0	1.60	20.80
14	1000	40.00	0	520.00	480.00	42.07	1.07	182.02	0	1.60	19.20
15	1000	40.00	0	560.00	440.00	42.07	1.07	183.09	0	1.60	17.60
16	1000	40.00	0	600.00	400.00	42.07	1.07	184.15	0	1.60	16.00
17	1000	40.00	0	640.00	360.00	0.00	-20.58	185.22	0	1.60	14.40
18	1000	40.00	0	680.00	320.00	0.00	-20.58	164.64	0	1.60	12.80
19	1000	40.00	0	720.00	280.00	0.00	-20.58	144.06	0	1.60	11.20
20	1000	40.00	0	760.00	240.00	0.00	-20.58	123.48	0	1.60	9.60
21	1000	40.00	0	800.00	200.00	0.00	-20.58	102.90	0	1.60	8.00
22	1000	40.00	0	840.00	160.00	0.00	-20.58	82.32	0	1.60	6.40
23	1000	40.00	0	880.00	120.00	0.00	-20.58	61.74	0	1.60	4.80
24	1000	40.00	0	920.00	80.00	0.00	-20.58	41.16	0	1.60	3.20
25	1000	40.00	0	960.00	40.00	0.00	-20.58	20.58	0	1.60	1.60

CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT

YEAR	MEAN NET INVESTMENT	EQUITY RETURN	INTEREST	TAXABLE INCOME	INVEST MENT TAX CREDIT	INCOME TAX	AD VALOREM TAX	REVENUE REQUIREMENT	PRESENT VALUE: $1 AT 10.98 %	PRESENT VALUE: MEAN ANNUAL SURVIVORS	PRESENT VALUE: REVENUE REQUIREMENT
	(1)-(4)-(8)	6.48% *(12)	4.50% *(12)	[(2)-(6)+(7) -(10)+(13)] *(1-.5145)		[.5145*(15)] -(16)	2.9% *(5)	(2)+(7)-(10) +(13)+(14)+(16) +(17)+(18)		(1)*(20)	(19)*(20)
	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
1	1000.00	64.80	45.00	45.18	40	-16.76	29.00	244.18	0.90106	901.06	220.02
2	916.27	59.37	41.23	49.62	0	25.53	27.84	228.07	0.81192	811.91	185.17
3	840.57	54.47	37.83	53.19	0	27.37	26.68	213.46	0.73159	731.59	156.12
4	771.91	50.02	34.74	55.99	0	28.81	25.52	199.99	0.65921	659.21	131.83
5	709.41	45.97	31.92	58.12	0	29.90	24.36	187.67	0.59399	593.99	111.48
6	652.29	42.27	29.35	59.65	0	30.69	23.20	176.32	0.53522	535.22	94.37
7	599.89	38.87	26.99	60.67	0	31.22	22.04	165.81	0.48227	482.27	79.96
8	551.60	35.74	24.82	61.24	0	31.51	20.88	156.03	0.43455	434.55	67.80
9	506.93	32.85	22.81	55.28	0	28.44	19.72	146.90	0.39156	391.56	57.52
10	462.25	29.95	20.80	56.33	0	28.98	18.56	137.76	0.35282	352.82	48.61
11	421.18	27.29	18.95	50.85	0	26.16	17.40	129.27	0.31791	317.91	41.10
12	380.12	24.63	17.11	45.36	0	23.34	16.24	120.78	0.28646	286.46	34.60
13	339.05	21.97	15.26	39.88	0	20.52	15.08	112.29	0.25812	258.12	28.99
14	297.98	19.31	13.41	34.40	0	17.70	13.92	103.81	0.23258	232.58	24.14
15	256.91	16.65	11.56	28.92	0	14.88	12.76	95.32	0.20957	209.57	19.98
16	215.85	13.99	9.71	23.44	0	12.06	11.60	86.83	0.18884	188.84	16.40
17	174.78	11.33	7.87	60.03	0	30.89	10.44	78.34	0.17015	170.15	13.33
18	155.36	10.07	6.99	57.44	0	29.55	9.28	73.71	0.15332	153.32	11.30
19	135.94	8.81	6.12	54.85	0	28.22	8.12	69.09	0.13815	138.15	9.54
20	116.52	7.55	5.24	52.26	0	26.89	6.96	64.46	0.12448	124.48	8.02
21	97.10	6.29	4.37	49.66	0	25.55	5.80	59.83	0.11217	112.17	6.71
22	77.68	5.03	3.50	47.07	0	24.22	4.64	55.21	0.10107	101.07	5.58
23	58.26	3.78	2.62	44.48	0	22.89	3.48	50.58	0.09107	91.07	4.61
24	38.84	2.52	1.75	41.89	0	21.55	2.32	45.96	0.08206	82.06	3.77
25	19.42	1.26	0.87	39.30	0	20.22	1.16	41.33	0.07394	73.94	3.06
										8434.06	1384.00

LEVELIZED REVENUE REQUIREMENT RELATING TO $1000 INCREMENTAL CAPITAL INVESTMENT = $ 1384. / $ 8434.06 = 16.4097 %

TABLE 16

DERIVATION OF ANNUAL ECONOMIC CHARGE RELATED TO CAPITAL INVESTMENT

(Using Service Life)

		Inflation Net of Technical Progress of 4 Percent	Inflation Net of Technical Progress of 2 Percent
		(1)	(2)
(1)	Present Value of Revenue Requirements Related to Incremental \$1,000 Investment[1]	\$1,384.00	\$1,384.00
(2)	Annual Charge Expressed in Constant Dollars Related to Incremental \$1,000 Investment[2]	\$120.32	\$141.44
(3)	Annual Economic Charge Related to Marginal Investment (2)÷\$1,000	12.03%	14.14%

[1] Schedule 15, page 3.

[2] Annual charge expressed in constant dollars is calculated using the following formula. The appropriate charge is the first year's charge which rises annually at the rate of inflation net of technical progress.

$$AC_t = K\,(r - j)\,(1 + j)^{t-1}\left[\frac{1}{1 - \left(\frac{1 + j}{1 + r}\right)^n}\right]$$

where:

AC_t = Annual Charge in Year t
t = Year
K = Present Value of Revenue Requirements
r = Overall Cost of Capital (10.98%)
j = Inflation Rate Net of Technical Progress
n = Service Life (25 years)

4

DERIVATION OF ANNUAL ECONOMIC CHARGE RELATED TO CAPITAL INVESTMENT

(Using Tax Life)

		Inflation Net of Technical Progress of 4 Percent	Inflation Net of Technical Progress of 2 Percent
		(1)	(2)
1)	Present Value of Revenue Requirements Related to Incremental $1,000 Investment[1]	$1,384.00	$1,384.00
2)	Annual Charge Expressed in Constant Dollars Related to Incremental $1,000 Investment[2]	$149.47	$167.78
3)	Annual Economic Charge Related to Marginal Investment (2)÷$1,000	14.95%	16.78%

[1] Schedule 15, page 2.
[2] Annual charge expressed in constant dollars is calculated using the following formula. The appropriate charge is the first year's charge which rises annually at the rate of inflation net of technical progress.

$$AC_t = K\,(r - j)\,(1 + j)^{t-1}\left[\frac{1}{1 - \left(\frac{1 + j}{1 + r}\right)^n}\right]$$

where:
AC_t = Annual Charge in Year t
t = Year
K = Present Value of Revenue Requirements
r = Overall Cost of Capital (10.98%)
j = Inflation Rate Net of Technical Progress
n = Tax Life (16 years)

TABLE 18

DEVELOPMENT OF CAPACITY ADJUSTMENT FACTORS

A. Development of Peak Loss Percentages

	corresponds to input Load[1] (Mwh) (1)	Variable Losses (Mwh) (2)	Losses as a Percent of Load (2)÷(1) (3)	System Load Factor (4)	Variable Peak Losses as a Percent of Peak Load (3)÷(4) (5)
Secondary	8,213,674	278,395	3.39%	0.59	5.75%
Primary	8,842,211	212,747	2.41	0.59	4.08
Sub-Transmission	12,861,567	124,914	0.97	0.59	1.64
Generation	12,986,481	198,612	1.53	0.59	2.59

B. Calculate Capacity Adjustment Factors

Expanded Capacity Adjustment Factors by Voltage Level

Demand Losses at Peak	Secondary (1)	Primary (2)	Sub-Transmission (3)	Generation (4)
Secondary Sales	2.46 ← 1.0575 = 1+5.75%	1.1006 = (1.0575 x (1+.0408))	1.1187	1.1477
Primary Sales		1.0408	1.0579	1.0853
Sub-Transmission Sales			1.0164	1.0427

[1] Sales.

DEVELOPMENT OF ENERGY ADJUSTMENT FACTORS

	Variable Peak Losses as a Percent of Peak Load	Load as a Percent of Peak Load	Variable Loss Factor (1)x(2)	Marginal Energy Loss Factor 2x[(3)÷[1-(3)]]		
	(1)	(2)	(3)	(4)		
evelopment of arginal Energy oss Factor at 5 Percent of eak Load						
Secondary	5.75%	75%	4.31%	9.0%	1.09	1.09 (.9174)
Primary	4.08	75	3.06	6.3	1.063	1.1587
Sub-Transmission	1.64	75	1.23	2.5	1.025	1.1876
Generation	2.59	75	1.94	4.0	1.04	1.2351

JR

Expanded Marginal Energy Adjustment Factors by Voltage Level

	Secondary	Primary	Sub-Transmission	Generation
	(1)	(2)	(3)	(4)
culate Marginal rgy Adjustment tors				
ondary Sales	1.090 .9174	1.159 .8628	1.188	1.236
mary Sales		1.063 .9407	1.090	1.134
-Transmission Sales			1.025 .9756	1.066

COMPUTATION OF MARGINAL UNIT COST
DEMAND-RELATED GENERATION

		Gas Turbine (1976 Dollars per Kw)
(1)	Long-Run Unit Investment[1]	$165.00
(2)	With General Plant Loading (1)x1.028	$169.62
(3)	Economic Carrying Charge[2]	14.95%
(4)	Administrative and General Loading[3]	0.20%
(5)	Total (3)+(4)	15.15%
(6)	Annualized Cost (2)x(5)	$ 25.70
(7)	Demand Related O&M Expenses	$ 1.20
(8)	With Administrative and General Loading (7)x1.22[4]	$ 1.46
	Working Capital	
(9)	Materials and Supplies (2)x3.0%	$ 5.09
(10)	Prepayments (2)x0.25%	$ 0.42
(11)	Operation and Maintenance Expense Allowance (8)x1/8	$ 0.18
(12)	Total Cash Working Capital (9)+(10)+(11)	$ 5.69
(13)	Revenue Requirement for Cash Working Capital (12)x15.75%	$ 0.90
(14)	Total Demand-Related Cost (6)+(8)+(13)	$ 28.06
(15)	Total Demand-Related Marginal Cost (Rounded)	$ 28.00

[1] Cost of a combustion turbine adjusted for planned reserve margin.
[2] Table 17, line (3), col. (1).
[3] Table 14, line (32).
[4] Table 14, line (30).

COMPUTATION OF MARGINAL UNIT COST
DEMAND-RELATED TRANSMISSION AND DISTRIBUTION

	Transmission Total	Distribution: Sub-Transmission	Distribution: Primary	Distribution: Secondary
	(1)	(2)	(3)	(4)
Long-Run Unit Investment	$90.79[1]	-	-	$192.00[2]
With General Plant Loading (1)x1.028	$93.33	-	-	197.38
Economic Carrying Charge[3]	14.95%	-	-	14.95%
Administrative and General Loading[4]	0.20%	-	-	0.20%
Total (3)+(4)	15.15%	-	-	15.15%
Annualized Cost (2)x(5)	$14.14	-	-	$ 29.90
Plant-Related Operations and Maintenance Expense	$ 1.02[5]	-	-	$ 2.25[6]
With Administrative and General Loading (7)x1.22[7]	$ 1.24	-	-	$ 2.75
Demand-Related Cost (6)+(8)	$15.38	-	-	$ 32.65
Working Capital				
Materials and Supplies (2)x3.0%	$ 2.80	-	-	$ 5.92
Prepayments (2)x0.25%	$ 0.23	-	-	$ 0.49
Operation and Maintenance Expense Allowance (8)x1/8	$ 0.16	-	-	$ 0.34
Total Cash Working Capital (10)+(11)+(12)	$ 3.19	-	-	$ 6.75
Revenue Requirement for Cash Working Capital (13)x15.75%	$ 0.50	-	-	$ 1.06
Total Demand-Related Cost (9)+(14)	$15.88	-	-	$ 33.71
Total Demand-Related Marginal Cost (Rounded)	$16.00	-	-	$ 34.00

Note: In this case all customers are served at secondary voltage; sub-transmission and primary costs have not been computed separately. For illustrative purposes sub-transmission and primary columns are displayed. In cases where customers are served from sub-transmission and primary voltages costs should be computed separately for each voltage level.

[1]Table 4.
[2]Table 8.
[3]Table 17, line (3), col. (1). The carrying charge calculated in our illustrative example is based upon the service life of a combustion turbine. In an actual marginal cost study, a separate carrying charge should be computed for each function as described in Section IX.
[4]Table 14, line (32).
[5]Table 5.
[6]Table 9.
[7]Table 14, line (30).

TABLE 21

COMPUTATION OF MARGINAL UNIT COST
CUSTOMER-RELATED

		Residential	Residential Water Heating	Residential All Electric	General	General All Electric	Industrial
		(1975 Dollars)					
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	Long-Run Unit Investment[1]	$379.00	$379.00	$379.00	$379.00	$379.00	$379.00
(2)	With General Plant Loading (1)x1.02	$386.58	$386.58	$386.58	$386.58	$386.58	$386.58
(3)	Economic Carrying Charge[2]	14.95%	14.95%	14.95%	14.95%	14.95%	14.95%
(4)	Administrative and General Loading[3]	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
(5)	Total (3)+(4)	15.15%	15.15%	15.15%	15.15%	15.15%	15.15%
(6)	Annualized Costs (5)x(2)	$58.57	$58.57	$58.57	$58.57	$58.57	$58.57
(7)	Plant-Related Operation and Maintenance Expenses[4]	$17.05	$17.05	$17.05	$17.05	$17.05	$17.05
(8)	With Administrative and General Loading (7)x1.22[5]	$20.80	$20.80	$20.80	$20.80	$20.80	$20.80
(9)	Customer Accounts Expenses[6]	$14.23	$14.23	$14.23	$21.35	$21.35	$56.92
(10)	Sales Expenses[7]	$0.70	$0.84	$1.40	$0.70	$1.40	$7.00
(11)	With Administrative and General Loading [(9)+(10)]x1.22[5]	$18.21	$18.39	$19.07	$26.90	$27.76	$77.98
(12)	Customer-Related Costs (6)+(8)+(11)	$97.58	$97.76	$98.44	$106.27	$107.13	$157.35
	Working Capital						
(13)	Materials and Supplies (2)x3.0%	$11.60	$11.60	$11.60	$11.60	$11.60	$11.60
(14)	Customer-Related Cash Working Capital [(8)+(11)]x1/8	$4.88	$4.90	$4.98	$5.96	$6.07	$12.35
(15)	Total Working Capital (13)+(14)	$16.48	$16.50	$16.58	$17.56	$17.67	$23.95
(16)	Revenue Requirement for Working Capital (15)x15.75%	$2.60	$2.60	$2.61	$2.77	$2.78	$3.77
(17)	Total Customer-Related Costs (12)+(16)	$100.18	$100.36	$101.05	$109.04	$109.91	$161.12
(18)	Total Marginal Costs (Rounded)	$100.00	$100.00	$101.00	$109.00	$110.00	$161.00

[1] Table 6.
[2] Table 17, line (3), col. (1). The carrying charge calculated in our illustrative example is based upon the service life of a combustion turbine. In an actual marginal cost study, carrying charges would be calculated separately for each function as described in Section IX.
[3] Table 14, line (32).
[4] Table 9.
[5] Table 14, line (30).
[6] Table 12.
[7] Table 13.

TABLE 22

4

MARGINAL DEMAND-RELATED UNIT COST BY COSTING PERIOD

Costing Period	System Segment: Secondary	System Segment: Primary	System Segment: Sub-Transmission	Allocation Factor	Relative Mean Peak Demand	Unit Cost: Secondary	Unit Cost: Primary	Unit Cost: Sub-Transmission
	(Dollars per Kw)					(Dollars per Kw)		
	(1)	(2)	(3)	(4)	(5)	[(1)x(4)]÷(5) (6)	[(2)x(4)]÷(5) (7)	[(3)x(4)]÷(5) (8)
Winter								
(1) Generation[1]	$32.14	-	-	0.87	0.96	$29.13	-	-
(2) Transmission[1]	$18.36	-	-	0.87	0.96	$16.64	-	-
(3) Distribution[2]	$36.98	-	-	0.87	0.96	$33.51	-	-
Base Running								
(4) Generation[1]	$32.14	-	-	0.13	0.86	$4.86	-	-
(5) Transmission[1]	$18.36	-	-	0.13	0.86	$2.78	-	-
(6) Distribution[2]	$36.98	-	-	0.13	0.86	$5.59	-	-

Note: In this case all service is at secondary voltage once again for illustrative purposes primary and sub-transmission columns have been displayed.

[1] Generation marginal unit cost from Table 20, page 1 and transmission marginal unit cost from Table 20, page 2 have been adjusted by capacity adjustment factor of 1.1477 from Table 18 to account for electric losses at time of peak between generation and transmission facitilies and the secondary voltage delivery level.

[2] Distribution marginal unit cost from Table 20, page 2 has been adjusted by capacity adjustment factor of 1.0875 to account for electric losses between components of the distribution system and the secondary voltage delivery level. Capacity adjustment factor of 1.0875 is a weighted average of the capacity adjustment factors for secondary sales of the secondary, primary and sub-transmission components of the distribution system. The voltage level component capacity adjustment factors are shown on Table 18.

Source: Col. (4): Table 1.

TABLE

SUMMARY OF COSTS BY POINT OF SERVICE AND COSTING PERIOD

	Costing Period: Winter (1)	Costing Period: Base Running (2)
Service From Secondary		
Seasonal Cost ($/Kw)		
Generation and Transmission	$45.77	$7.64
Distribution	$33.51	$5.59
Peak Period Seasonal Energy Cost (¢/Kwh)	2.63¢	2.15¢
Off-Peak Period Seasonal Energy Cost (¢/Kwh)	1.11¢	1.11¢
Service From Primary		
Seasonal Cost ($/Kw)		
Generation and Transmission	-	-
Distribution	-	-
Peak Period Seasonal Energy Cost (¢/Kwh)	-	-
Off-Peak Period Seasonal Energy Cost (¢/Kwh)	-	-
Service From Sub-Transmission		
Seasonal Cost ($/Kw)		
Generation and Transmission	-	-
Distribution	-	-
Peak Period Seasonal Energy Cost (¢/Kwh)	-	-
Off-Peak Period Seasonal Energy Cost (¢/Kwh)	-	-

Note: Primary and sub-transmission are displayed only for illustrative purposes. In this case all customers are served at secondary voltage.

Source: Capacity costs are from Table 22. Energy costs are from Table 24.

TABLE 24

MARGINAL ENERGY COST BY COSTING PERIOD

	Costing Period: Peak Hours, Winter	Peak Hours, Base Running	Off-Peak Hours
	(1)	(2)	(3)
Marginal Running Cost[1] (Cents/Kwh)	2.02¢	1.64¢	0.81¢
A&G Expenses[2] (Cents/Kwh)	0.07¢	0.07¢	0.07¢
Cash Working Capital (Cents/Kwh) 1/8x[(1)+(2)]	0.26¢	0.21¢	0.11¢
Revenue Requirement for Cash Working Capital (Cents/Kwh) (3)x15.75%	0.04¢	0.03¢	0.02¢
Marginal Energy Cost (Cents/Kwh) (1)+(2)+(4)	2.13¢	1.74¢	0.90¢
Incremental Energy Loss Factor for Secondary Service[3]	1.236	1.236	1.236
Marginal Energy Cost Including Losses for Secondary Service (Cents/Kwh) (5)x(6)	2.63¢	2.15¢	1.11¢
Incremental Energy Loss Factor for Primary Service	-	-	-
Marginal Energy Cost Including Losses for Primary Service (Cents/Kwh) (5)x(8)	-	-	-
Incremental Energy Loss Factor for Sub-Transmission Service	-	-	-
Marginal Energy Cost Including Losses for Sub-Transmission Service (Cents/Kwh) (5)x(10)	-	-	-

Note: The display of primary and sub-transmission level delivery is only for illustrative purposes. Only numbers applicable to this case are shown.

[1] Table 2.
[2] Table 14, line (34).
[3] For illustrative purposes, the energy adjustment factor computed on Table 19 has been used for all periods. In an actual case, energy adjustment factors based on the mean load in each costing period would be computed separately.

TABLE

SUMMARY OF ANNUAL MARGINAL CUSTOMER COSTS BY CUSTOMER CLASS

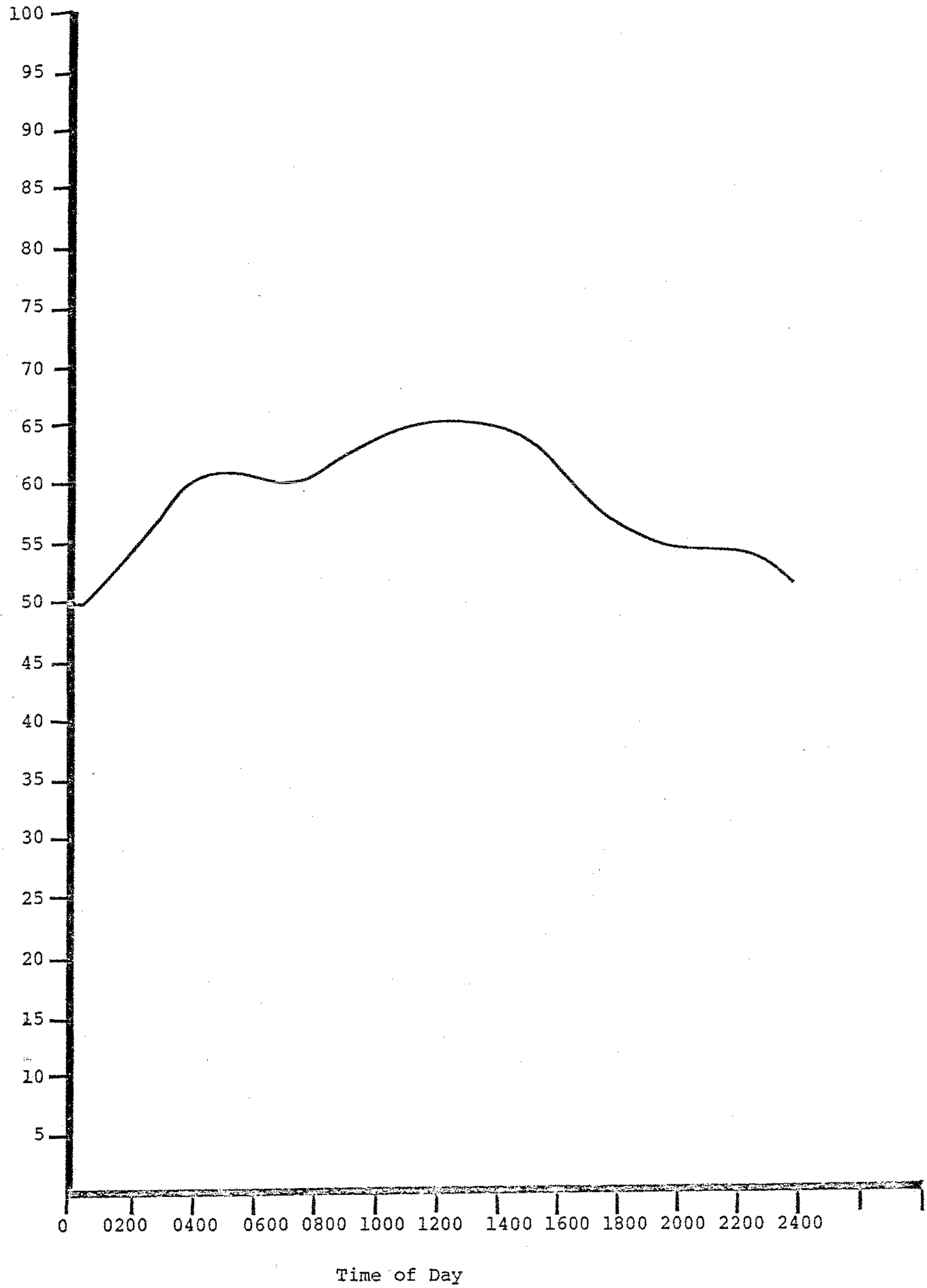
Customer Class	Annual Marginal Customer Cost
Residential	$100.00
Residential With Water Heating	$100.00
Residential--All Electric	$101.00
General	$109.00
General--All Electric	$110.00
Industrial	$161.00

Source: Table 21.

FIGURE 1

4

WINTER SEASON AVERAGE WEEKEND LOAD CURVE



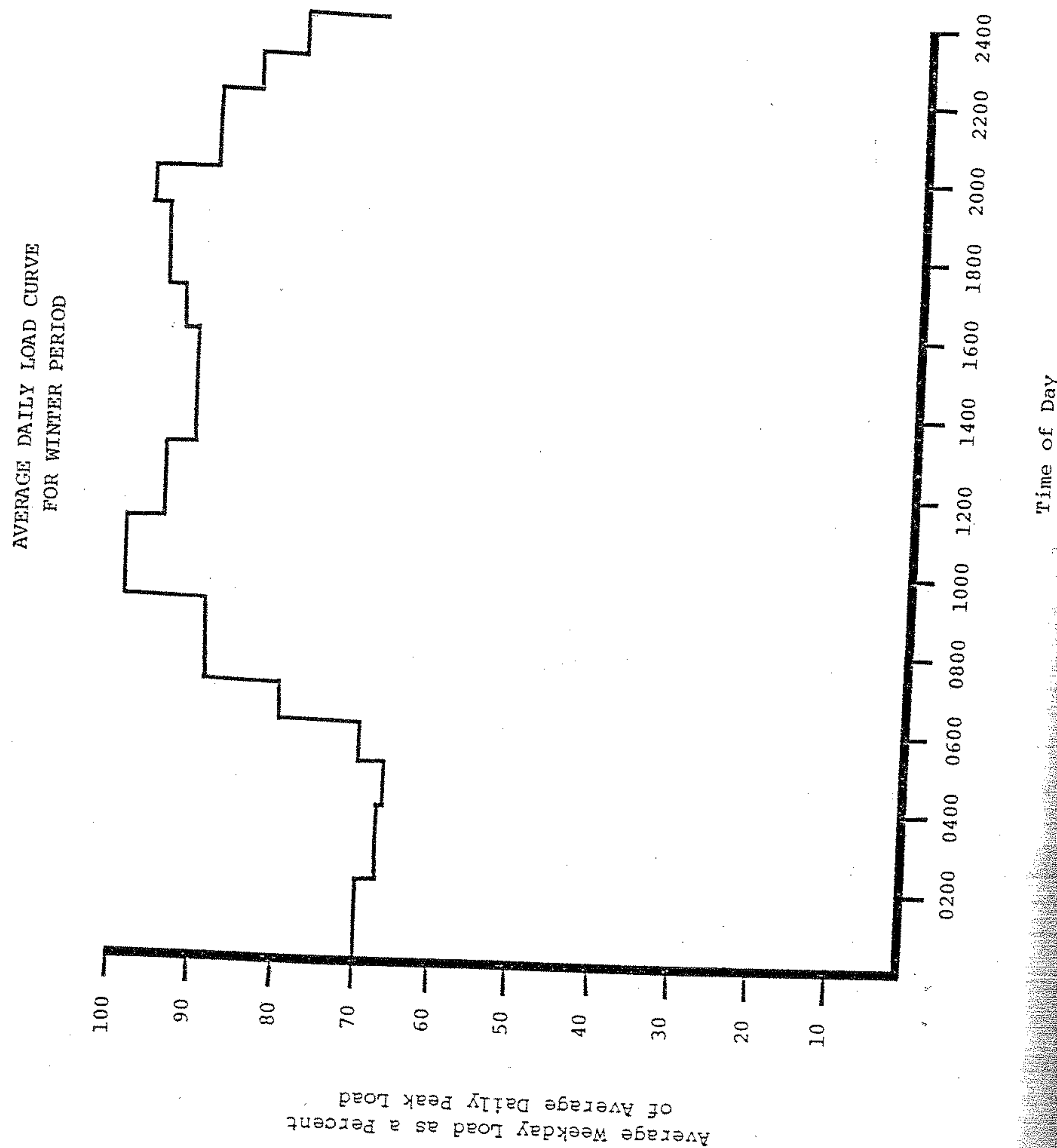
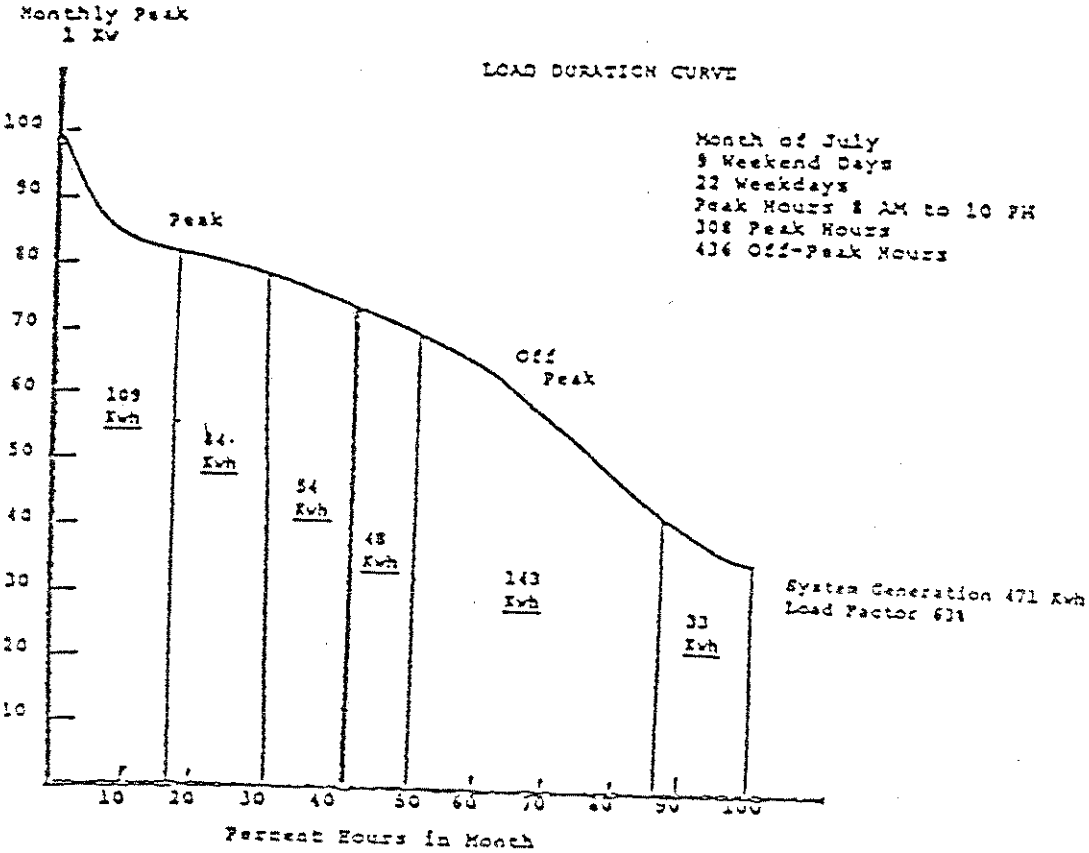
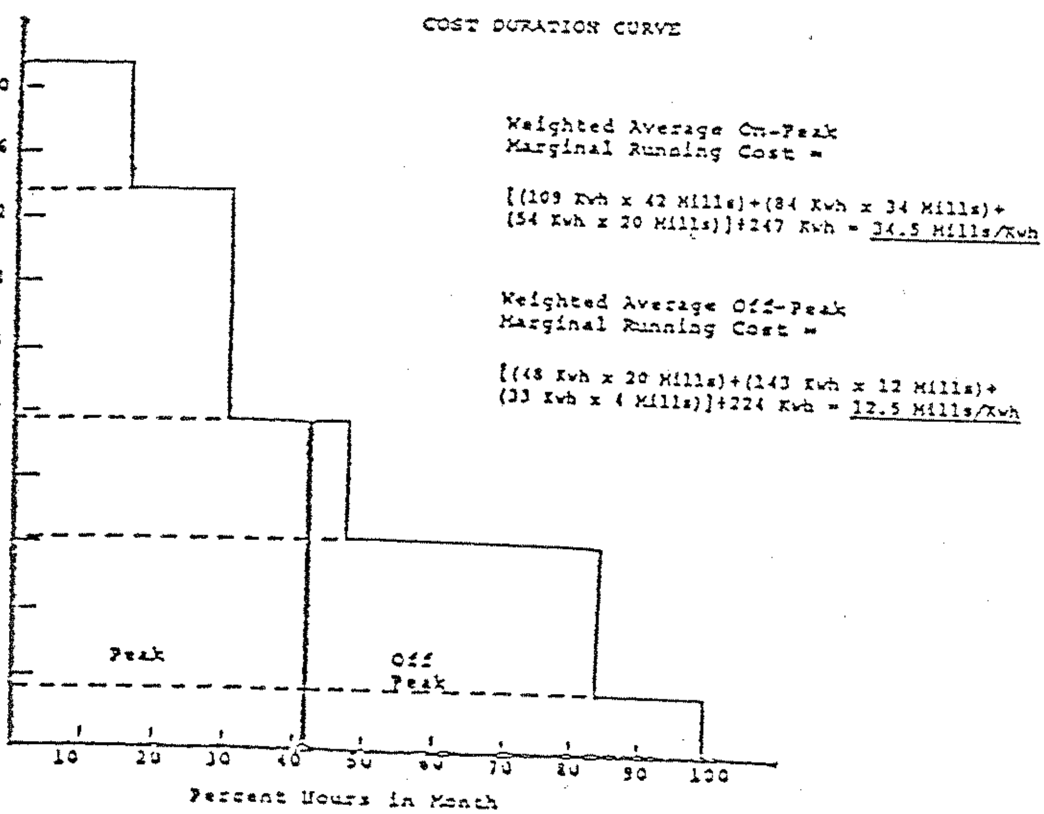

AVERAGE DAILY LOAD CURVE
FOR WINTER PERIOD
Average Weekday Load as a Percent
of Average Daily Peak Load
100
90
80
70
60
50
40
30
20
10
0200
0400
0600
0800
1000
1200
1400
1600
1800
2000
2200
2400
Time of Day

FIGURE 3

4

CALCULATION OF MARGINAL RUNNING
COST BY PRICING PERIOD





COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-90: Refer to the Company's response to DTE 15-5:

a) Provide the output files and all the data used by the Company to estimate the regression equations presented in part a) and part b). Please specify the statistical results of the final regression equation specification (e.g., Ajusted R^2 , t-statistics);
b) specify which test or tests were performed in the analysis to detect serial autocorrelation in the residual and multicollinearity of the data. In addition, indicate the method used to correct the serial autocorrelation problem. Provide evidence to support your answer;
c) explain how the Company derived the average incremental cost of $434.54/DDD.

Response: a) Output files and all data are shown on the tab labeled "DTE 15-5" of the Excel spreadsheet labeled "Attachment RR-DTE-90 - Cochran Orcott Adjustment.xls," which is being provided on CD to the Department.

As indicated in the file, the R^2 = .98
$t_{constant}$ = -9.2
t_{DDD} = -4.8
t_{DDD^2} = 8.6

b) The Durbin-Watson test detected serial correlation. The Cochran Orcott Adjustment procedure was applied to raise the D-W from 1.00 to 1.63. See Attachment RR-DTE-90 (B), which was taken from the spreadsheet provided in response to part a).

c) Incremental Average $= \dfrac{\Delta \text{ Investment}}{\Delta \text{ Load}}$

$$= \frac{141{,}402{,}730 - 0}{551{,}630 - 226{,}225}$$

$$= \$434.54$$

Statistics for Regressions in DTE-15-10

	Form	Dependent Variable	Independent Variable	Marginal Cost Estimate	R-Squared	t-Statistics	Durbin-Watson Statistic
1	Y=a+bx	Cumulative Growth-related Distribution Investment ($2004)	Firm Design Day Demand	$ 455.16	0.89	a = -6.96 b = 14.38	1.30
2	Y=a+b*ln(x)	Cumulative Growth-related Distribution Investment ($2004)	Natural log of Firm Design Day Demand	$ 313.35	0.93	a = -17.67 b = 18.38	1.54
3	Y=a+bx+cz	Cumulative Growth-related Distribution Investment ($2004)	Firm Design Day Demand and Firm Customer Count	$170.57 per DD Dt and $913.16 per Cust	0.95	a = -9.8 b = 3.33 c = 6.03	1.50
4	Y=a+b* ln(x) +c* ln(z)	Cumulative Growth-related Distribution Investment ($2004)	Natural log of Firm Design Day Demand and Natural log of Firm Customer Count	$263.58 per DD Dt and $1303.17 per Cust	0.96	a = -14.01 b = 3.9 c = 5.3	1.49

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2 Distribution Capacity-Related Expenses

R SQUARED, ADJUSTED = 0.77
DURBIN WATSON STATISTIC = 0.97

		Before Cochrane Orcott Adjustment	
DPEUC =	Dist Plt Expense Unit Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		1427	9.728
YEAR =	Year	$ (0.70701)	-9.594
=			

Line Estimate Results

(0.70701)	1,427	#N/A	#N/A
0.073695	147	#N/A	#N/A
0.773184	3	#N/A	#N/A
92.0393	27	#N/A	#N/A
1,014.71	297.67	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR DPEUC YEAR

YEAR	DIST PLT EXPENSE UNIT COST	YEAR	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	32.12	1,976	29.65	2.47	32.12
1977	38.22	1,977	28.94	9.28	38.22
1978	33.32	1,978	28.23	5.09	33.32
1979	23.84	1,979	27.53	(3.69)	23.84
1980	27.31	1,980	26.82	0.49	27.31
1981	25.86	1,981	26.11	(0.26)	25.86
1982	23.47	1,982	25.41	(1.93)	23.47
1983	20.85	1,983	24.70	(3.85)	20.85
1984	21.05	1,984	23.99	(2.94)	21.05
1985	26.46	1,985	23.29	3.17	26.46
1986	20.18	1,986	22.58	(2.40)	20.18
1987	19.46	1,987	21.87	(2.41)	19.46
1988	20.67	1,988	21.16	(0.50)	20.67
1989	19.65	1,989	20.46	(0.81)	19.65
1990	18.23	1,990	19.75	(1.52)	18.23
1991	15.50	1,991	19.04	(3.54)	15.50
1992	13.34	1,992	18.34	(4.99)	13.34
1993	12.77	1,993	17.63	(4.86)	12.77
1994	13.98	1,994	16.92	(2.94)	13.98
1995	16.95	1,995	16.22	0.74	16.95
1996	17.81	1,996	15.51	2.30	17.81
1997	15.09	1,997	14.80	0.29	15.09
1998	14.14	1,998	14.09	0.04	14.14
1999	17.16	1,999	13.39	3.77	17.16
2000	16.62	2,000	12.68	3.94	16.62
2001	14.21	2,001	11.97	2.24	14.21
2002	11.68	2,002	11.27	0.41	11.68
2003	11.41	2,003	10.56	0.85	11.41
2004	11.39	2,004	9.85	1.54	11.39

REGRESSION MODEL NO. 2 Distribution Capacity-Related Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.47
DURBIN WATSON STATISTIC = 1.67

	After Cochrane Orcott Adjustment			
	X-VARIABLE COEFF.	t STATISTIC		
	648	4.831		13
$	(0.65427)	-4.763		8
				4.72

Line Estimate Results

(0.65427)	648	#N/A	#N/A
0.137352	134	#N/A	#N/A
0.466012	3	#N/A	#N/A
22.6903	26	#N/A	#N/A
188	215	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

		TRANSFORMED VARIABLES									ORIGINAL		RHO	0.50965		
	Y	X1	X2	X3	ESTIMATED		ADJUSTED FORECAST	ORIGINAL FORECAST		ADJUSTED FORECAST	ESTIMATED + RESIDUAL			LAGGED		
YEAR	UNIT COST	YEAR	N/A	N/A	(Y)'t	RESIDUAL	(Y)	(Y)'	DIFFERENCE	(Y)	(Y)	DIFFERENCE	ERROR	ERROR	ERROR^2	E(t)*E(t-1)
1976													2			
1977	22	970	-	-	13.42	8.43	29.79	28.94	0.85	29.8	38.2	(8.4)	9	2	86	23
1978	14	970	-	-	13.10	0.74	32.58	28.23	4.35	32.6	33.3	(0.7)	5	9	26	47
1979	7	971	-	-	12.78	(5.92)	29.76	27.53	2.24	29.8	23.8	5.9	(4)	5	14	(19)
1980	15	971	-	-	12.46	2.70	24.61	26.82	(2.21)	24.6	27.3	(2.7)	0	(4)	0	(2)
1981	12	972	-	-	12.14	(0.20)	26.06	26.11	(0.06)	26.1	25.9	0.2	(0)	0	0	(0)
1982	10	972	-	-	11.82	(1.52)	25.00	25.41	(0.41)	25.0	23.5	1.5	(2)	(0)	4	0
1983	9	973	-	-	11.50	(2.61)	23.46	24.70	(1.24)	23.5	20.8	2.6	(4)	(2)	15	7
1984	10	973	-	-	11.18	(0.74)	21.80	23.99	(2.19)	22	21	1	(3)	(4)	9	11
1985	16	974	-	-	10.86	4.87	21.59	23.29	(1.70)	22	26	(5)	3	(3)	10	(9)
1986	7	974	-	-	10.53	(3.84)	24.02	22.58	1.44	24	20	4	(2)	3	6	(8)
1987	9	975	-	-	10.21	(1.04)	20.50	21.87	(1.37)	20	19	1	(2)	(2)	6	6
1988	11	975	-	-	9.89	0.86	19.81	21.16	(1.36)	20	21	(1)	(0)	(2)	0	1
1989	9	976	-	-	9.57	(0.45)	20.11	20.46	(0.35)	20	20	0	(1)	(0)	1	0
1990	8	976	-	-	9.25	(1.03)	19.27	19.75	(0.48)	19	18	1	(2)	(1)	2	1
1991	6	977	-	-	8.93	(2.72)	18.22	19.04	(0.82)	18	16	3	(4)	(2)	13	5
1992	5	977	-	-	8.61	(3.17)	16.51	18.34	(1.83)	17	13	3	(5)	(4)	25	18
1993	6	978	-	-	8.29	(2.32)	15.09	17.63	(2.54)	15	13	2	(5)	(5)	24	24
1994	7	978	-	-	7.97	(0.50)	14.48	16.92	(2.44)	14	14	0	(3)	(5)	9	14
1995	10	979	-	-	7.65	2.18	14.77	16.22	(1.44)	15	17	(2)	1	(3)	1	(2)
1996	9	979	-	-	7.33	1.84	15.97	15.51	0.46	16	18	(2)	2	1	5	2
1997	6	980	-	-	7.01	(0.99)	16.08	14.80	1.28	16	15	1	0	2	0	1
1998	6	980	-	-	6.68	(0.24)	14.38	14.09	0.28	14	14	0	0	0	0	0
1999	10	981	-	-	6.36	3.59	13.57	13.39	0.18	14	17	(4)	4	0	14	0
2000	8	981	-	-	6.04	1.83	14.79	12.68	2.11	15	17	(2)	4	4	15	15
2001	6	982	-	-	5.72	0.02	14.19	11.97	2.22	14	14	(0)	2	4	5	9
2002	4	982	-	-	5.40	(0.97)	12.64	11.27	1.38	13	12	1	0	2	0	1
2003	5	983	-	-	5.08	0.38	11.03	10.56	0.47	11	11	(0)	1	0	1	0
2004	6	983	-	-	4.76	0.82	**10.57**	9.85	0.72	11	11	(1)	2	1	2	1
												SUM	(2)	(2)	292	149

ORIGINAL REGRESSION D-W

SLOPE	0.50289404
INTERCEPT	-0.060588531
DURBIN-WATSON	0.97
R-SQUARED	0.773

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
2				6	
9	2	7	46	86	23
5	9	(4)	18	26	47
(4)	5	(9)	77	14	(19)
0	(4)	4	17	0	(2)
(0)	0	(1)	1	0	(0)
(2)	(0)	(2)	3	4	0
(4)	(2)	(2)	4	15	7
(3)	(4)	1	1	9	11
3	(3)	6	37	10	(9)
(2)	3	(6)	31	6	(8)
(2)	(2)	(0)	0	6	6
(0)	(2)	2	4	0	1
(1)	(0)	(0)	0	1	0
(2)	(1)	(1)	1	2	1
(4)	(2)	(2)	4	13	5
(5)	(4)	(1)	2	25	18
(5)	(5)	0	0	24	24
(3)	(5)	2	4	9	14
1	(3)	4	14	1	(2)
2	1	2	2	5	2
0	2	(2)	4	0	1
0	0	(0)	0	0	0
4	0	4	14	14	0
4	4	0	0	15	15
2	4	(2)	3	5	9
0	2	(2)	3	0	1
1	0	0	0	1	0
2	1	1	0	2	1
(2)	(2)	(1)	290	298	149

TRANSFORMED REGRESSION D-W

SLOPE	-0.004252628
INTERCEPT	-0.312287385
DURBIN-WATSON	1.67
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
8				71	
1	8	(8)	59	1	6
(6)	1	(7)	44	35	(4)
3	(6)	9	74	7	(16)
(0)	3	(3)	8	0	(1)
(2)	(0)	(1)	2	2	0
(3)	(2)	(1)	1	7	4
(1)	(3)	2	3	1	2
5	(1)	6	32	24	(4)
(4)	5	(9)	76	15	(19)
(1)	(4)	3	8	1	4
1	(1)	2	4	1	(1)
(0)	1	(1)	2	0	(0)
(1)	(0)	(1)	0	1	0
(3)	(1)	(2)	3	7	3
(3)	(3)	(0)	0	10	9
(2)	(3)	1	1	5	7
(0)	(2)	2	3	0	1
2	(0)	3	7	5	(1)
2	2	(0)	0	3	4
(1)	2	(3)	8	1	(2)
(0)	(1)	1	1	0	0
4	(0)	4	15	13	(1)
2	4	(2)	3	3	7
0	2	(2)	3	0	0
(1)	0	(1)	1	1	(0)
0	(1)	1	2	0	(0)
1	0	0	0	1	0
(0)	(1)	(8)	361	215	(1)

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2A Distribution Capacity-Related Expenses

R SQUARED, ADJUSTED = 0.78
DURBIN WATSON STATISTIC = 1.02

		Before Cochrane Orcott Adjustment	
DPEUC =	Dist Plt Expense Unit Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		2070	2.431
YEAR =	Year	$ (1.04011)	-2.362
CUST =	Cust'S	0.000	0.7674

Line Estimate Results

0.00008	(1)	2,070	#N/A
0.000107	0	852	#N/A
0.778208	3	#N/A	#N/A
45.6134	26	#N/A	#N/A
1,021.30	291.08	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid
YEAR	DPEUC	YEAR	CUST

YEAR	DIST PLT EXPENSE UNIT COST	YEAR	CUST'S	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	32.12	1,976	184779	30.46	1.66	32.12
1977	38.22	1,977	184321	29.38	8.84	38.22
1978	33.32	1,978	185232.00	28.42	4.91	33.32
1979	23.84	1,979	189091.00	27.69	(3.85)	23.84
1980	27.31	1,980	192620.00	26.95	0.37	27.31
1981	25.86	1,981	194544.00	26.06	(0.21)	25.86
1982	23.47	1,982	195276.00	25.08	(1.61)	23.47
1983	20.85	1,983	197836.00	24.26	(3.41)	20.85
1984	21.05	1,984	195276.00	23.00	(1.95)	21.05
1985	26.46	1,985	202626.00	22.57	3.89	26.46
1986	20.18	1,986	207842.00	21.96	(1.78)	20.18
1987	19.46	1,987	213657.00	21.40	(1.94)	19.46
1988	20.67	1,988	219556.00	20.85	(0.18)	20.67
1989	19.65	1,989	226230.00	20.36	(0.71)	19.65
1990	18.23	1,990	230551.00	19.67	(1.44)	18.23
1991	15.50	1,991	255325.92	20.67	(5.17)	15.50
1992	13.34	1,992	241232.00	18.47	(5.13)	13.34
1993	12.77	1,993	245550.00	17.79	(5.01)	12.77
1994	13.98	1,994	248710.00	17.01	(3.03)	13.98
1995	16.95	1,995	252840.84	16.31	0.65	16.95
1996	17.81	1,996	257364.00	15.64	2.17	17.81
1997	15.09	1,997	261170.00	14.92	0.18	15.09
1998	14.14	1,998	265545.00	14.24	(0.10)	14.14
1999	17.16	1,999	272085.80	13.74	3.43	17.16
2000	16.62	2,000	273808.00	12.84	3.78	16.62
2001	14.21	2,001	276749.00	12.04	2.17	14.21
2002	11.68	2,002	279495.00	11.23	0.45	11.68
2003	11.41	2,003	281227	10.33	1.08	11.41
2004	11.39	2,004	283032	9.44	1.96	11.39

REGRESSION MODEL NO. 2A Distribution Capacity-Related Expenses (Multi-regression) WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.49
DURBIN WATSON STATISTIC = 1.63

	After Cochrane Orcott Adjustment	
	X-VARIABLE COEFF.	t STATISTIC
	696	1.392
$	(0.66914)	-1.337
	0.000003	0.024

Line Estimate Results

0.00000	(1)	696	#N/A
0.000116	1	500	#N/A
0.493485	3	#N/A	#N/A
12.1784	25	#N/A	#N/A
210	216	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

	TRANSFORMED VARIABLES										ORIGINAL		RHO	0.48429		
	Y	X1	X2	X3	ESTIMATED		ADJUSTED FORECAST	ORIGINAL FORECAST		ADJUSTED FORECAST	ESTIMATED + RESIDUAL			LAGGED		
YEAR	UNIT COST	YEAR	N/A	N/A	(Y)'t	RESIDUAL	(Y)	(Y)'	DIFFERENCE	(Y)	(Y)	DIFFERENCE	ERROR	ERROR	ERROR^2	E(t)*E(t-1)
1976													2			
1977	23	1,020	94,834	-	14.18	8.48	29.74	29.38	0.36	29.7	38.2	(8.5)	9	2	78	15
1978	15	1,021	95,967	-	13.84	0.97	32.35	28.42	3.93	32.3	33.3	(1.0)	5	9	24	43
1979	8	1,021	99,385	-	13.50	(5.80)	29.64	27.69	1.95	29.6	23.8	5.8	(4)	5	15	(19)
1980	16	1,022	101,045	-	13.16	2.60	24.71	26.95	(2.24)	24.7	27.3	(2.6)	0	(4)	0	(1)
1981	13	1,022	101,260	-	12.82	(0.19)	26.05	26.06	(0.02)	26.0	25.9	0.2	(0)	0	0	(0)
1982	11	1,023	101,060	-	12.47	(1.52)	25.00	25.08	(0.09)	25.0	23.5	1.5	(2)	(0)	3	0
1983	9	1,023	103,265	-	12.13	(2.66)	23.50	24.26	(0.75)	23.5	20.8	2.7	(3)	(2)	12	5
1984	11	1,024	99,466	-	11.78	(0.82)	21.87	23.00	(1.13)	22	21	1	(2)	(3)	4	7
1985	16	1,024	108,055	-	11.46	4.80	21.65	22.57	(0.92)	22	26	(5)	4	(2)	15	(8)
1986	7	1,025	109,712	-	11.12	(3.75)	23.93	21.96	1.97	24	20	4	(2)	4	3	(7)
1987	10	1,025	113,001	-	10.78	(1.10)	20.55	21.40	(0.84)	21	19	1	(2)	(2)	4	3
1988	11	1,026	116,084	-	10.45	0.80	19.87	20.85	(0.98)	20	21	(1)	(0)	(2)	0	0
1989	10	1,026	119,901	-	10.11	(0.47)	20.12	20.36	(0.24)	20	20	0	(1)	(0)	0	0
1990	9	1,027	120,990	-	9.77	(1.05)	19.29	19.67	(0.39)	19	18	1	(1)	(1)	2	1
1991	7	1,027	143,672	-	9.49	(2.81)	18.32	20.67	(2.36)	18	16	3	(5)	(1)	27	7
1992	6	1,028	117,580	-	9.07	(3.23)	16.58	18.47	(1.89)	17	13	3	(5)	(5)	26	27
1993	6	1,028	128,723	-	8.76	(2.44)	15.22	17.79	(2.57)	15	13	2	(5)	(5)	25	26
1994	8	1,029	129,792	-	8.41	(0.62)	14.60	17.01	(2.41)	15	14	1	(3)	(5)	9	15
1995	10	1,029	132,393	-	8.08	2.11	14.85	16.31	(1.46)	15	17	(2)	1	(3)	0	(2)
1996	10	1,030	134,915	-	7.74	1.86	15.95	15.64	0.31	16	18	(2)	2	1	5	1
1997	6	1,030	136,531	-	7.40	(0.93)	16.02	14.92	1.11	16	15	1	0	2	0	0
1998	7	1,031	139,063	-	7.06	(0.23)	14.37	14.24	0.13	14	14	0	(0)	0	0	(0)
1999	10	1,031	143,485	-	6.73	3.59	13.57	13.74	(0.16)	14	17	(4)	3	(0)	12	(0)
2000	8	1,032	142,039	-	6.38	1.93	14.69	12.84	1.85	15	17	(2)	4	3	14	13
2001	6	1,032	144,146	-	6.04	0.12	14.09	12.04	2.05	14	14	(0)	2	4	5	8
2002	5	1,033	145,468	-	5.70	(0.90)	12.58	11.23	1.35	13	12	1	0	2	0	1
2003	6	1,033	145,870	-	5.35	0.40	11.01	10.33	0.68	11	11	(0)	1	0	1	0
2004	6	1,034	146,836	-	5.01	0.86	$\boxed{\mathbf{10.54}}$	9.44	1.10	11	11	(1)	2	1	4	2
												SUM	(2)	(2)	288	140

ORIGINAL REGRESSION D-W

SLOPE	0.485925328
INTERCEPT	-0.025360365
DURBIN-WATSON	1.02
R-SQUARED	0.778

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
2				3	
9	2	7	52	78	15
5	9	(4)	15	24	43
(4)	5	(9)	77	15	(19)
0	(4)	4	18	0	(1)
(0)	0	(1)	0	0	(0)
(2)	(0)	(1)	2	3	0
(3)	(2)	(2)	3	12	5
(2)	(3)	1	2	4	7
4	(2)	6	34	15	(8)
(2)	4	(6)	32	3	(7)
(2)	(2)	(0)	0	4	3
(0)	(2)	2	3	0	0
(1)	(0)	(1)	0	0	0
(1)	(1)	(1)	1	2	1
(5)	(1)	(4)	14	27	7
(5)	(5)	0	0	26	27
(5)	(5)	0	0	25	26
(3)	(5)	2	4	9	15
1	(3)	4	13	0	(2)
2	1	2	2	5	1
0	2	(2)	4	0	0
(0)	0	(0)	0	0	(0)
3	(0)	4	12	12	(0)
4	3	0	0	14	13
2	4	(2)	3	5	8
0	2	(2)	3	0	1
1	0	1	0	1	0
2	1	1	1	4	2
(2)	(2)	0	296	291	140

TRANSFORMED REGRESSION D-W

SLOPE	0.016159045
INTERCEPT	-0.313674189
DURBIN-WATSON	1.63
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
8				72	
1	8	(8)	56	1	8
(6)	1	(7)	46	34	(6)
3	(6)	8	71	7	(15)
(0)	3	(3)	8	0	(0)
(2)	(0)	(1)	2	2	0
(3)	(2)	(1)	1	7	4
(1)	(3)	2	3	1	2
5	(1)	6	32	23	(4)
(4)	5	(9)	73	14	(18)
(1)	(4)	3	7	1	4
1	(1)	2	4	1	(1)
(0)	1	(1)	2	0	(0)
(1)	(0)	(1)	0	1	0
(3)	(1)	(2)	3	8	3
(3)	(3)	(0)	0	10	9
(2)	(3)	1	1	6	8
(1)	(2)	2	3	0	2
2	(1)	3	7	4	(1)
2	2	(0)	0	3	4
(1)	2	(3)	8	1	(2)
(0)	(1)	1	0	0	0
4	(0)	4	15	13	(1)
2	4	(2)	3	4	7
0	2	(2)	3	0	0
(1)	0	(1)	1	1	(0)
0	(1)	1	2	0	(0)
1	0	0	0	1	0
0	(1)	(8)	351	216	4

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2B Distribution Capacity-Related Unit cost vs Year and Plt Investment

R SQUARED, ADJUSTED = 0.77
DURBIN WATSON STATISTIC = 0.98

DPEUC = Dist Plt Expense Unit Cost

		Before Cochrane Orcott Adjustment X-VARIABLE COEFF.	t STATISTIC
CONSTANT		1721	1.689
YEAR =	Year	$ (0.85576)	-1.660
DTI =	Distr Plant Invest	2.47E-08	0.2917

Line Estimate Results

2.47E-08	(1)	1,721	#N/A
8.46E-08	1	1,019	#N/A
0.773924	3	#N/A	#N/A
44.5028	26	#N/A	#N/A
1.02E+03	2.97E+02	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	DPEUC	YEAR	DTI			
YEAR	DIST PLT EXPENSE UNIT COST	YEAR	DISTR PLANT INVEST	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	32.12	1,976	-	29.81	2.31	32.12
1977	38.22	1,977	4,271,252	29.06	9.16	38.22
1978	33.32	1,978	8,709,537	28.31	5.01	33.32
1979	23.84	1,979	14,171,669	27.59	(3.75)	23.84
1980	27.31	1,980	17,555,811	26.82	0.49	27.31
1981	25.86	1,981	20,482,450	26.04	(0.18)	25.86
1982	23.47	1,982	25,131,748	25.29	(1.82)	23.47
1983	20.85	1,983	26,864,548	24.48	(3.64)	20.85
1984	21.05	1,984	30,623,182	23.72	(2.66)	21.05
1985	26.46	1,985	37,471,980	23.03	3.42	26.46
1986	20.18	1,986	45,457,524	22.37	(2.19)	20.18
1987	19.46	1,987	56,022,555	21.78	(2.32)	19.46
1988	20.67	1,988	64,157,785	21.12	(0.45)	20.67
1989	19.65	1,989	70,317,222	20.42	(0.77)	19.65
1990	18.23	1,990	77,529,058	19.74	(1.51)	18.23
1991	15.50	1,991	85,179,871	19.07	(3.57)	15.50
1992	13.34	1,992	90,741,028	18.36	(5.01)	13.34
1993	12.77	1,993	109,280,404	17.96	(5.18)	12.77
1994	13.98	1,994	115,788,625	17.26	(3.28)	13.98
1995	16.95	1,995	120,821,863	16.53	0.42	16.95
1996	17.81	1,996	124,794,681	15.77	2.04	17.81
1997	15.09	1,997	127,968,212	15.00	0.10	15.09
1998	14.14	1,998	131,965,544	14.24	(0.10)	14.14
1999	17.16	1,999	135,453,840	13.47	3.69	17.16
2000	16.62	2,000	138,343,843	12.68	3.93	16.62
2001	14.21	2,001	141,063,792	11.90	2.32	14.21
2002	11.68	2,002	143,813,174	11.11	0.57	11.68
2003	11.41	2,003	145,956,482	10.30	1.10	11.41
2004	11.39	2,004	149,025,071	9.52	1.87	11.39

REGRESSION MODEL NO. 2B Distribution Capacity-Related Unit cost vs Year and Plt Investment WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =		0.47
DURBIN WATSON STATISTIC =		1.67

After Cochrane Orcott Adjustment

X-VARIABLE COEFF.	t STATISTIC
579	0.784
$ (0.57758)	-0.765
-1.28E-08	-0.104

Line Estimate Results

-1.28E-08	(1)	579	#N/A
1.23E-07	1	739	#N/A
0.471170	3	#N/A	#N/A
11.1371	25	#N/A	#N/A
192	215	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

RHO 0.50522

YEAR	Y UNIT COST	X1 YEAR	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2	E(t)*E(t-1)
	TRANSFORMED VARIABLES															
1976													2			
1977	22	979	4,271,252	-	13.53	8.46	30	29	1	29.8	38.2	(8.5)	9	2	84	21
1978	14	979	6,551,602	-	13.21	0.80	33	28	4	32.5	33.3	(0.8)	5	9	25	46
1979	7	980	9,771,410	-	12.89	(5.88)	30	28	2	29.7	23.8	5.9	(4)	5	14	(19)
1980	15	980	10,395,957	-	12.59	2.67	25	27	(2)	24.6	27.3	(2.7)	0	(4)	0	(2)
1981	12	981	11,612,849	-	12.29	(0.23)	26	26	0	26.1	25.9	0.2	(0)	0	0	(0)
1982	10	981	14,783,542	-	11.97	(1.56)	25	25	(0)	25.0	23.5	1.6	(2)	(0)	3	0
1983	9	982	14,167,408	-	11.69	(2.70)	24	24	(1)	23.5	20.8	2.7	(4)	(2)	13	7
1984	11	982	17,050,592	-	11.36	(0.84)	22	24	(2)	22	21	1	(3)	(4)	7	10
1985	16	983	22,000,441	-	11.02	4.80	22	23	(1)	22	26	(5)	3	(3)	12	(9)
1986	7	983	26,525,815	-	10.67	(3.86)	24	22	2	24	20	4	(2)	3	5	(8)
1987	9	984	33,056,364	-	10.30	(1.04)	20	22	(1)	20	19	1	(2)	(2)	5	5
1988	11	984	35,853,898	-	9.98	0.86	20	21	(1)	20	21	(1)	(0)	(2)	0	1
1989	9	985	37,903,228	-	9.67	(0.46)	20	20	(0)	20	20	0	(1)	(0)	1	0
1990	8	985	42,003,175	-	9.33	(1.02)	19	20	(0)	19	18	1	(2)	(1)	2	1
1991	6	986	46,010,402	-	8.99	(2.70)	18	19	(1)	18	16	3	(4)	(2)	13	5
1992	6	986	47,706,191	-	8.69	(3.18)	17	18	(2)	17	13	3	(5)	(4)	25	18
1993	6	987	63,435,942	-	8.20	(2.17)	15	18	(3)	15	13	2	(5)	(5)	27	26
1994	8	987	60,577,643	-	7.95	(0.42)	14	17	(3)	14	14	0	(3)	(5)	11	17
1995	10	988	62,322,778	-	7.64	2.25	15	17	(2)	15	17	(2)	0	(3)	0	(1)
1996	9	988	63,752,687	-	7.34	1.91	16	16	0	16	18	(2)	2	0	4	1
1997	6	989	64,919,059	-	7.04	(0.94)	16	15	1	16	15	1	0	2	0	0
1998	7	989	67,313,050	-	6.72	(0.21)	14	14	0	14	14	0	(0)	0	0	(0)
1999	10	990	68,781,802	-	6.41	3.60	14	13	0	14	17	(4)	4	(0)	14	(0)
2000	8	990	69,909,436	-	6.11	1.83	15	13	2	15	17	(2)	4	4	15	15
2001	6	991	71,169,290	-	5.81	0.00	14	12	2	14	14	(0)	2	4	5	9
2002	4	991	72,544,491	-	5.51	(1.01)	13	11	2	13	12	1	1	2	0	1
2003	6	992	73,298,747	-	5.21	0.29	11	10	1	11	11	(0)	1	1	1	1
2004	6	992	75,284,488	-	4.90	0.73	11	10	1	11	11	(1)	2	1	3	2
												SUM	(2)	(2)	291	147

ORIGINAL REGRESSION D-W

SLOPE	0.501734496
INTERCEPT	-0.049026062
DURBIN-WATSON	0.98
R-SQUARED	0.774

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
2				5	
9	2	7	47	84	21
5	9	(4)	17	25	46
(4)	5	(9)	77	14	(19)
0	(4)	4	18	0	(2)
(0)	0	(1)	0	0	(0)
(2)	(0)	(2)	3	3	0
(4)	(2)	(2)	3	13	7
(3)	(4)	1	1	7	10
3	(3)	6	37	12	(9)
(2)	3	(6)	32	5	(8)
(2)	(2)	(0)	0	5	5
(0)	(2)	2	3	0	1
(1)	(0)	(0)	0	1	0
(2)	(1)	(1)	1	2	1
(4)	(2)	(2)	4	13	5
(5)	(4)	(1)	2	25	18
(5)	(5)	(0)	0	27	26
(3)	(5)	2	4	11	17
0	(3)	4	14	0	(1)
2	0	2	3	4	1
0	2	(2)	4	0	0
(0)	0	(0)	0	0	(0)
4	(0)	4	14	14	(0)
4	4	0	0	15	15
2	4	(2)	3	5	9
1	2	(2)	3	0	1
1	1	1	0	1	1
2	1	1	1	3	2
(2)	(2)	(0)	290	297	147

TRANSFORMED REGRESSION D-W

SLOPE	-0.001836361
INTERCEPT	-0.31350827
DURBIN-WATSON	1.67
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
8				72	
1	8	(8)	59	1	7
(6)	1	(7)	45	35	(5)
3	(6)	9	73	7	(16)
(0)	3	(3)	8	0	(1)
(2)	(0)	(1)	2	2	0
(3)	(2)	(1)	1	7	4
(1)	(3)	2	3	1	2
5	(1)	6	32	23	(4)
(4)	5	(9)	75	15	(19)
(1)	(4)	3	8	1	4
1	(1)	2	4	1	(1)
(0)	1	(1)	2	0	(0)
(1)	(0)	(1)	0	1	0
(3)	(1)	(2)	3	7	3
(3)	(3)	(0)	0	10	9
(2)	(3)	1	1	5	7
(0)	(2)	2	3	0	1
2	(0)	3	7	5	(1)
2	2	(0)	0	4	4
(1)	2	(3)	8	1	(2)
(0)	(1)	1	1	0	0
4	(0)	4	15	13	(1)
2	4	(2)	3	3	7
0	2	(2)	3	0	0
(1)	0	(1)	1	1	(0)
0	(1)	1	2	0	(0)
1	0	0	0	1	0
0	(1)	(8)	359	215	(0)

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2C Distribution Capacity-Related Expenses - Year and Plt Investment

R SQUARED, ADJUSTED = 0.13
DURBIN WATSON STATISTIC = 1.12

		Before Cochrane Orcott Adjustment	
DPETC =	Distr Expense Total Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		462729081	1.854
YEAR =	Year	(230,614)	-1.827
DTI =	Distr Plant Invest	3.55%	1.7155

Line Estimate Results

3.55E-02	(230,614)	4.63E+08	#N/A
2.07E-02	126,217	2.50E+08	#N/A
0.125747	827,287	#N/A	#N/A
1.8698	26	#N/A	#N/A
2.56E+12	1.78E+13	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	DPETC	YEAR	DTI			
YEAR	DISTR EXPENSE TOTAL COST	YEAR	DISTR PLANT INVEST	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	$7,266,430	1,976	-	7036111	230319	7266430
1977	$8,482,448	1,977	4,271,252	6957237	1525211	8482448
1978	$7,730,844	1,978	8,709,537	6884296	846549	7730844
1979	$6,092,196	1,979	14,171,669	6847728	-755532	6092196
1980	$6,854,979	1,980	17,555,811	6737338	117642	6854979
1981	$6,852,095	1,981	20,482,450	6610695	241401	6852095
1982	$6,643,007	1,982	25,131,748	6545250	97757	6643007
1983	$5,440,661	1,983	26,864,548	6376195	-935534	5440661
1984	$5,608,312	1,984	30,623,182	6279109	-670797	5608312
1985	$7,185,645	1,985	37,471,980	6291803	893841	7185645
1986	$5,901,049	1,986	45,457,524	6344881	-443832	5901049
1987	$5,985,548	1,987	56,022,555	6489597	-504049	5985548
1988	$6,556,706	1,988	64,157,785	6547992	8714	6556706
1989	$6,690,804	1,989	70,317,222	6536196	154608	6690804
1990	$6,686,164	1,990	77,529,058	6561788	124376	6686164
1991	$5,860,228	1,991	85,179,871	6602974	-742746	5860228
1992	$5,165,797	1,992	90,741,028	6569924	-1404127	5165797
1993	$5,183,455	1,993	109,280,404	6997933	-1814478	5183455
1994	$5,894,116	1,994	115,788,625	6998528	-1104412	5894116
1995	$7,395,029	1,995	120,821,863	6946723	448305	7395029
1996	$8,071,139	1,996	124,794,681	6857246	1213892	8071139
1997	$7,084,742	1,997	127,968,212	6739374	345368	7084742
1998	$6,745,913	1,998	131,965,544	6650768	95145	6745913
1999	$7,462,087	1,999	135,453,840	6544078	918009	7462087
2000	$7,403,537	2,000	138,343,843	6416134	987404	7403537
2001	$6,479,700	2,001	141,063,792	6282148	197553	6479700
2002	$5,433,491	2,002	143,813,174	6149208	-715717	5433491
2003	$6,227,392	2,003	145,956,482	5994736	232656	6227392
2004	$6,285,609	2,004	149,025,071	5873136	412473	6285609

REGRESSION MODEL NO. 2C Distribution Capacity-Related Expenses - Year and Plt Investment WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =		0.04
DURBIN WATSON STATISTIC =		1.57

After Cochrane Orcott Adjustment

X-VARIABLE COEFF.	t STATISTIC
203195550	1.009
(178,671)	-0.990
2.79%	0.948

Line Estimate Results

2.79E-02	(178,671)	2.03E+08	#N/A
2.94E-02	180,415	2.01E+08	#N/A
0.038669	756,220	#N/A	#N/A
0.5028	25	#N/A	#N/A
5.75E+11	1.43E+13	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

	TRANSFORMED VARIABLES										ORIGINAL		RHO	0.43548		
YEAR	Y TOTAL COST	X1 YEAR	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2	E(t)*E(t-1)
1976													230,319			
1977	5,318,092	1,116	4,271,252	-	3,828,756	1,489,336	6,993,112	6,957,237	35,875	6,993,112.0	8,482,448.1	(1,489,336.1)	1,525,211	230,319	2.33E+12	3.51E+11
1978	4,036,942	1,117	6,849,509	-	3,799,776	237,166	7,493,678	6,884,296	609,383	7,493,678.3	7,730,844.4	(237,166.1)	846,549	1,525,211	7.17E+11	1.29E+12
1979	2,725,599	1,118	10,378,875	-	3,797,313	(1,071,714)	7,163,910	6,847,728	316,182	7,163,910.1	6,092,195.9	1,071,714.2	(755,532)	846,549	5.71E+11	-6.40E+11
1980	4,201,974	1,118	11,384,390	-	3,724,484	477,491	6,377,489	6,737,338	(359,849)	6,377,488.6	6,854,979.2	(477,490.7)	117,642	(755,532)	1.38E+10	-8.89E+10
1981	3,866,916	1,119	12,837,316	-	3,664,128	202,788	6,649,307	6,610,695	38,612	6,649,307.0	6,852,095.2	(202,788.2)	241,401	117,642	5.83E+10	2.84E+10
1982	3,659,085	1,119	16,212,134	-	3,657,356	1,728	6,641,279	6,545,250	96,029	6,641,279.3	6,643,007.4	(1,728.1)	97,757	241,401	9.56E+09	2.36E+10
1983	2,547,791	1,120	15,920,275	-	3,548,355	(1,000,564)	6,441,225	6,376,195	65,030	6,441,225.4	5,440,661.2	1,000,564.2	(935,534)	97,757	8.75E+11	-9.15E+10
1984	3,239,035	1,120	18,924,317	-	3,531,246	(292,211)	5,900,523	6,279,109	(378,586)	5,900,523	5,608,312	292,211	(670,797)	(935,534)	4.50E+11	6.28E+11
1985	4,743,359	1,121	24,136,320	-	3,575,696	1,167,663	6,017,982	6,291,803	(273,822)	6,017,982	7,185,645	(1,167,663)	893,841	(670,797)	7.99E+11	-6.00E+11
1986	2,771,874	1,122	29,139,377	-	3,614,321	(842,447)	6,743,497	6,344,881	398,616	6,743,497	5,901,049	842,447	(443,832)	893,841	1.97E+11	-3.97E+11
1987	3,415,783	1,122	36,226,895	-	3,711,062	(295,279)	6,280,827	6,489,597	(208,770)	6,280,827	5,985,548	295,279	(504,049)	(443,832)	2.54E+11	2.24E+11
1988	3,950,144	1,123	39,761,309	-	3,708,740	241,404	6,315,302	6,547,992	(232,690)	6,315,302	6,556,706	(241,404)	8,714	(504,049)	7.59E+07	-4.39E+09
1989	3,835,516	1,123	42,378,048	-	3,680,832	154,684	6,536,120	6,536,196	(76)	6,536,120	6,690,804	(154,684)	154,608	8,714	2.39E+10	1.35E+09
1990	3,772,479	1,124	46,907,597	-	3,706,255	66,224	6,619,940	6,561,788	58,152	6,619,940	6,686,164	(66,224)	124,376	154,608	1.55E+10	1.92E+10
1991	2,948,565	1,124	51,417,829	-	3,731,140	(782,575)	6,642,803	6,602,974	39,829	6,642,803	5,860,228	782,575	(742,746)	124,376	5.52E+11	-9.24E+10
1992	2,613,808	1,125	53,647,241	-	3,692,433	(1,078,625)	6,244,422	6,569,924	(325,502)	6,244,422	5,165,797	1,078,625	(1,404,127)	(742,746)	1.97E+12	1.04E+12
1993	2,933,875	1,126	69,764,866	-	4,040,940	(1,107,065)	6,290,520	6,997,933	(707,413)	6,290,520	5,183,455	1,107,065	(1,814,478)	(1,404,127)	3.29E+12	2.55E+12
1994	3,636,846	1,126	68,199,635	-	3,896,436	(259,590)	6,153,706	6,998,528	(844,822)	6,153,706	5,894,116	259,590	(1,104,412)	(1,814,478)	1.22E+12	2.00E+12
1995	4,828,283	1,127	70,398,699	-	3,856,884	971,399	6,423,630	6,946,723	(523,094)	6,423,630	7,395,029	(971,399)	448,305	(1,104,412)	2.01E+11	-4.95E+11
1996	4,850,781	1,127	72,179,662	-	3,805,674	1,045,107	7,026,031	6,857,246	168,785	7,026,031	8,071,139	(1,045,107)	1,213,892	448,305	1.47E+12	5.44E+11
1997	3,569,955	1,128	73,623,127	-	3,745,055	(175,100)	7,259,842	6,739,374	520,467	7,259,842	7,084,742	175,100	345,368	1,213,892	1.19E+11	4.19E+11
1998	3,660,679	1,128	76,238,462	-	3,717,108	(56,430)	6,802,343	6,650,768	151,575	6,802,343	6,745,913	56,430	95,145	345,368	9.05E+09	3.29E+10
1999	4,524,404	1,129	77,986,017	-	3,664,967	859,437	6,602,650	6,544,078	58,572	6,602,650	7,462,087	(859,437)	918,009	95,145	8.43E+11	8.73E+10
2000	4,153,978	1,129	79,356,950	-	3,602,326	551,652	6,851,886	6,416,134	435,752	6,851,886	7,403,537	(551,652)	987,404	918,009	9.75E+11	9.06E+11
2001	3,255,638	1,130	80,818,372	-	3,542,207	(286,570)	6,766,270	6,282,148	484,122	6,766,270	6,479,700	286,570	197,553	987,404	3.90E+10	1.95E+11
2002	2,611,737	1,131	82,383,282	-	3,484,974	(873,237)	6,306,728	6,149,208	157,520	6,306,728	5,433,491	873,237	(715,717)	197,553	5.12E+11	-1.41E+11
2003	3,861,237	1,131	83,329,300	-	3,410,486	450,752	5,776,641	5,994,736	(218,096)	5,776,641	6,227,392	(450,752)	232,656	(715,717)	5.41E+10	-1.67E+11
2004	3,573,729	1,132	85,464,530	-	3,369,153	204,576	6,081,033	5,873,136	207,897	6,081,033	6,285,609	(204,576)	412,473	232,656	1.70E+11	9.60E+10
												SUM	(230,319)	(412,473)	1.77E+13	7.73E+12

ORIGINAL REGRESSION D-W

SLOPE	0.438327665
INTERCEPT	-1768.579202
DURBIN-WATSON	1.12
R-SQUARED	0.126

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
230,319				##########	
1.53E+06	2.30E+05	1.29E+06	1.68E+12	2.33E+12	3.51E+11
8.47E+05	1.53E+06	-6.79E+05	4.61E+11	7.17E+11	1.29E+12
-7.56E+05	8.47E+05	-1.60E+06	2.57E+12	5.71E+11	-6.40E+11
1.18E+05	-7.56E+05	8.73E+05	7.62E+11	1.38E+10	-8.89E+10
2.41E+05	1.18E+05	1.24E+05	1.53E+10	5.83E+10	2.84E+10
9.78E+04	2.41E+05	-1.44E+05	2.06E+10	9.56E+09	2.36E+10
-9.36E+05	9.78E+04	-1.03E+06	1.07E+12	8.75E+11	-9.15E+10
-6.71E+05	-9.36E+05	2.65E+05	7.01E+10	4.50E+11	6.28E+11
8.94E+05	-6.71E+05	1.56E+06	2.45E+12	7.99E+11	-6.00E+11
-4.44E+05	8.94E+05	-1.34E+06	1.79E+12	1.97E+11	-3.97E+11
-5.04E+05	-4.44E+05	-6.02E+04	3.63E+09	2.54E+11	2.24E+11
8.71E+03	-5.04E+05	5.13E+05	2.63E+11	7.59E+07	-4.39E+09
1.55E+05	8.71E+03	1.46E+05	2.13E+10	2.39E+10	1.35E+09
1.24E+05	1.55E+05	-3.02E+04	9.14E+08	1.55E+10	1.92E+10
-7.43E+05	1.24E+05	-8.67E+05	7.52E+11	5.52E+11	-9.24E+10
-1.40E+06	-7.43E+05	-6.61E+05	4.37E+11	1.97E+12	1.04E+12
-1.81E+06	-1.40E+06	-4.10E+05	1.68E+11	3.29E+12	2.55E+12
-1.10E+06	-1.81E+06	7.10E+05	5.04E+11	1.22E+12	2.00E+12
4.48E+05	-1.10E+06	1.55E+06	2.41E+12	2.01E+11	-4.95E+11
1.21E+06	4.48E+05	7.66E+05	5.86E+11	1.47E+12	5.44E+11
3.45E+05	1.21E+06	-8.69E+05	7.54E+11	1.19E+11	4.19E+11
9.51E+04	3.45E+05	-2.50E+05	6.26E+10	9.05E+09	3.29E+10
9.18E+05	9.51E+04	8.23E+05	6.77E+11	8.43E+11	8.73E+10
9.87E+05	9.18E+05	6.94E+04	4.82E+09	9.75E+11	9.06E+11
1.98E+05	9.87E+05	-7.90E+05	6.24E+11	3.90E+10	1.95E+11
-7.16E+05	1.98E+05	-9.13E+05	8.34E+11	5.12E+11	-1.41E+11
2.33E+05	-7.16E+05	9.48E+05	8.99E+11	5.41E+10	-1.67E+11
4.12E+05	2.33E+05	1.80E+05	3.23E+10	1.70E+11	9.60E+10
-2.30E+05	-4.12E+05	1.82E+05	1.99E+13	1.78E+13	7.73E+12

TRANSFORMED REGRESSION D-W

SLOPE	0.13639578
INTERCEPT	-54127.14103
DURBIN-WATSON	1.57
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1.49E+06				2.22E+12	
2.37E+05	1.49E+06	-1.25E+06	1.57E+12	5.62E+10	3.53E+11
-1.07E+06	2.37E+05	-1.31E+06	1.71E+12	1.15E+12	-2.54E+11
4.77E+05	-1.07E+06	1.55E+06	2.40E+12	2.28E+11	-5.12E+11
2.03E+05	4.77E+05	-2.75E+05	7.55E+10	4.11E+10	9.68E+10
1.73E+03	2.03E+05	-2.01E+05	4.04E+10	2.99E+06	3.50E+08
-1.00E+06	1.73E+03	-1.00E+06	1.00E+12	1.00E+12	-1.73E+09
-2.92E+05	-1.00E+06	7.08E+05	5.02E+11	8.54E+10	2.92E+11
1.17E+06	-2.92E+05	1.46E+06	2.13E+12	1.36E+12	-3.41E+11
-8.42E+05	1.17E+06	-2.01E+06	4.04E+12	7.10E+11	-9.84E+11
-2.95E+05	-8.42E+05	5.47E+05	2.99E+11	8.72E+10	2.49E+11
2.41E+05	-2.95E+05	5.37E+05	2.88E+11	5.83E+10	-7.13E+10
1.55E+05	2.41E+05	-8.67E+04	7.52E+09	2.39E+10	3.73E+10
6.62E+04	1.55E+05	-8.85E+04	7.83E+09	4.39E+09	1.02E+10
-7.83E+05	6.62E+04	-8.49E+05	7.20E+11	6.12E+11	-5.18E+10
-1.08E+06	-7.83E+05	-2.96E+05	8.76E+10	1.16E+12	8.44E+11
-1.11E+06	-1.08E+06	-2.84E+04	8.09E+08	1.23E+12	1.19E+12
-2.60E+05	-1.11E+06	8.47E+05	7.18E+11	6.74E+10	2.87E+11
9.71E+05	-2.60E+05	1.23E+06	1.52E+12	9.44E+11	-2.52E+11
1.05E+06	9.71E+05	7.37E+04	5.43E+09	1.09E+12	1.02E+12
-1.75E+05	1.05E+06	-1.22E+06	1.49E+12	3.07E+10	-1.83E+11
-5.64E+04	-1.75E+05	1.19E+05	1.41E+10	3.18E+09	9.88E+09
8.59E+05	-5.64E+04	9.16E+05	8.39E+11	7.39E+11	-4.85E+10
5.52E+05	8.59E+05	-3.08E+05	9.47E+10	3.04E+11	4.74E+11
-2.87E+05	5.52E+05	-8.38E+05	7.03E+11	8.21E+10	-1.58E+11
-8.73E+05	-2.87E+05	-5.87E+05	3.44E+11	7.63E+11	2.50E+11
4.51E+05	-8.73E+05	1.32E+06	1.75E+12	2.03E+11	-3.94E+11
2.05E+05	4.51E+05	-2.46E+05	6.06E+10	4.19E+10	9.22E+10
-7.34E-07	-2.05E+05	-1.28E+06	2.24E+13	1.43E+13	1.96E+12

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2D Distribution Capacity-Related Expenses - Ln(Year) and Ln(Plt Investment)

R SQUARED, ADJUSTED = 0.04
DURBIN WATSON STATISTIC = 1.12

		Before Cochrane Orcott Adjustment	
DPETC =	Distr Expense Total Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		160913485	0.501
LN(YEAR) =	Ln(Year)	(20,281,474)	-0.479
LN(DTI) =	Ln Distr Plant Invest	-1710193.39%	-0.6828

Line Estimate Results

-1.71E+04	(20,281,474)	1.61E+08	#N/A
2.50E+04	42,333,455	3.21E+08	#N/A
0.044118	865,047	#N/A	#N/A
0.6000	26	#N/A	#N/A
8.98E+11	1.95E+13	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR DPETC LN(YEAR) LN(DTI)

YEAR	DISTR EXPENSE TOTAL COST	LN(YEAR)	LN DISTR PLANT INVEST	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	$7,266,430	7.59	(21)	7355239	-88809	7266430
1977	$8,482,448	7.59	15.27	6729467	1752981	8482448
1978	$7,730,844	7.59	15.98	6707026	1023819	7730844
1979	$6,092,196	7.59	16.47	6688449	-596253	6092196
1980	$6,854,979	7.59	16.68	6674541	180438	6854979
1981	$6,852,095	7.59	16.84	6661664	190432	6852095
1982	$6,643,007	7.59	17.04	6647930	-4922	6643007
1983	$5,440,661	7.59	17.11	6636559	-1195898	5440661
1984	$5,608,312	7.59	17.24	6624095	-1015782	5608312
1985	$7,185,645	7.59	17.44	6610423	575222	7185645
1986	$5,901,049	7.59	17.63	6596904	-695855	5901049
1987	$5,985,548	7.59	17.84	6583121	-597573	5985548
1988	$6,556,706	7.59	17.98	6570597	-13891	6556706
1989	$6,690,804	7.60	18.07	6558830	131974	6690804
1990	$6,686,164	7.60	18.17	6546966	139197	6686164
1991	$5,860,228	7.60	18.26	6535167	-674939	5860228
1992	$5,165,797	7.60	18.32	6523902	-1358105	5165797
1993	$5,183,455	7.60	18.51	6510544	-1327088	5183455
1994	$5,894,116	7.60	18.57	6499380	-605264	5894116
1995	$7,395,029	7.60	18.61	6488484	906545	7395029
1996	$8,071,139	7.60	18.64	6477767	1593371	8071139
1997	$7,084,742	7.60	18.67	6467179	617563	7084742
1998	$6,745,913	7.60	18.70	6456500	289414	6745913
1999	$7,462,087	7.60	18.72	6445905	1016182	7462087
2000	$7,403,537	7.60	18.75	6435401	968137	7403537
2001	$6,479,700	7.60	18.76	6424930	54771	6479700
2002	$5,433,491	7.60	18.78	6414466	-980975	5433491
2003	$6,227,392	7.60	18.80	6404085	-176693	6227392
2004	$6,285,609	7.60	18.82	6393607	-107998	6285609

REGRESSION MODEL NO. 2D Distribution Capacity-Related Expenses - Ln(Year) and Ln(Plt Investment) WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.19
DURBIN WATSON STATISTIC = 1.77

After Cochrane Orcott Adjustment	
X-VARIABLE COEFF.	t STATISTIC
-22444108	-0.090
5,850,128	0.099
11963186.75%	2.413

Line Estimate Results

1.20E+05	5,850,128	-2.24E+07	#N/A
4.96E+04	58,814,380	2.50E+08	#N/A
0.192195	692,855	#N/A	#N/A
2.9740	25	#N/A	#N/A
2.86E+12	1.20E+13	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

	TRANSFORMED VARIABLES											ORIGINAL		RHO	0.44156		
	Y	X1	X2	X3	ESTIMATED		ADJUSTED FORECAST	ORIGINAL FORECAST		ADJUSTED FORECAST	ESTIMATED + RESIDUAL						
YEAR	TOTAL COST	LN(YEAR)	N/A	N/A	(Y)'t	RESIDUAL	(Y)	(Y)'	DIFFERENCE	(Y)	(Y)	DIFFERENCE		ERROR	LAGGED ERROR	ERROR^2	E(t)*E(t-1)
1976														(88,809)			
1977	5,273,862	4	24	-	5,272,191	1,671	8,480,777	6,729,467	1,751,310	8,480,777.4	8,482,448.1	(1,670.7)		1,752,981	(88,809)	3.07E+12	-1.56E+11
1978	3,985,309	4	9	-	3,457,874	527,436	7,203,409	6,707,026	496,383	7,203,408.5	7,730,844.4	(527,435.9)		1,023,819	1,752,981	1.05E+12	1.79E+12
1979	2,678,541	4	9	-	3,480,126	(801,584)	6,893,780	6,688,449	205,331	6,893,780.2	6,092,195.9	801,584.3		(596,253)	1,023,819	3.56E+11	-6.10E+11
1980	4,164,891	4	9	-	3,481,677	683,214	6,171,765	6,674,541	(502,776)	6,171,764.9	6,854,979.2	(683,214.4)		180,438	(596,253)	3.26E+10	-1.08E+11
1981	3,825,190	4	9	-	3,490,459	334,731	6,517,364	6,661,664	(144,300)	6,517,363.9	6,852,095.2	(334,731.3)		190,432	180,438	3.63E+10	3.44E+10
1982	3,617,376	4	10	-	3,508,435	108,941	6,534,066	6,647,930	(113,864)	6,534,066.1	6,643,007.4	(108,941.4)		(4,922)	190,432	2.42E+07	-9.37E+08
1983	2,507,355	4	10	-	3,507,252	(999,897)	6,440,558	6,636,559	(196,001)	6,440,558.3	5,440,661.2	999,897.1		(1,195,898)	(4,922)	1.43E+12	5.89E+09
1984	3,205,918	4	10	-	3,521,042	(315,124)	5,923,437	6,624,095	(700,658)	5,923,437	5,608,312	315,124		(1,015,782)	(1,195,898)	1.03E+12	1.21E+12
1985	4,709,222	4	10	-	3,539,916	1,169,305	6,016,340	6,610,423	(594,083)	6,016,340	7,185,645	(1,169,305)		575,222	(1,015,782)	3.31E+11	-5.84E+11
1986	2,728,135	4	10	-	3,554,010	(825,875)	6,726,925	6,596,904	130,021	6,726,925	5,901,049	825,875		(695,855)	575,222	4.84E+11	-4.00E+11
1987	3,379,863	4	10	-	3,570,449	(190,586)	6,176,134	6,583,121	(406,986)	6,176,134	5,985,548	190,586		(597,573)	(695,855)	3.57E+11	4.16E+11
1988	3,913,710	4	10	-	3,577,274	336,436	6,220,271	6,570,597	(350,327)	6,220,271	6,556,706	(336,436)		(13,891)	(597,573)	1.93E+08	8.30E+09
1989	3,795,606	4	10	-	3,582,721	212,885	6,477,920	6,558,830	(80,911)	6,477,920	6,690,804	(212,885)		131,974	(13,891)	1.74E+10	-1.83E+09
1990	3,731,752	4	10	-	3,591,200	140,552	6,545,612	6,546,966	(1,355)	6,545,612	6,686,164	(140,552)		139,197	131,974	1.94E+10	1.84E+10
1991	2,907,866	4	10	-	3,598,942	(691,076)	6,551,304	6,535,167	16,137	6,551,304	5,860,228	691,076		(674,939)	139,197	4.56E+11	-9.39E+10
1992	2,578,137	4	10	-	3,603,176	(1,025,039)	6,190,836	6,523,902	(333,066)	6,190,836	5,165,797	1,025,039		(1,358,105)	(674,939)	1.84E+12	9.17E+11
1993	2,902,431	4	10	-	3,623,715	(721,284)	5,904,739	6,510,544	(605,804)	5,904,739	5,183,455	721,284		(1,327,088)	(1,358,105)	1.76E+12	1.80E+12
1994	3,605,294	4	10	-	3,622,453	(17,159)	5,911,275	6,499,380	(588,106)	5,911,275	5,894,116	17,159		(605,264)	(1,327,088)	3.66E+11	8.03E+11
1995	4,792,405	4	10	-	3,626,125	1,166,280	6,228,748	6,488,484	(259,736)	6,228,748	7,395,029	(1,166,280)		906,545	(605,264)	8.22E+11	-5.49E+11
1996	4,805,768	4	10	-	3,629,384	1,176,384	6,894,755	6,477,767	416,988	6,894,755	8,071,139	(1,176,384)		1,593,371	906,545	2.54E+12	1.44E+12
1997	3,520,826	4	10	-	3,632,315	(111,489)	7,196,231	6,467,179	729,052	7,196,231	7,084,742	111,489		617,563	1,593,371	3.81E+11	9.84E+11
1998	3,617,554	4	10	-	3,636,303	(18,749)	6,764,663	6,456,500	308,163	6,764,663	6,745,913	18,749		289,414	617,563	8.38E+10	1.79E+11
1999	4,483,342	4	10	-	3,639,433	843,908	6,618,179	6,445,905	172,274	6,618,179	7,462,087	(843,908)		1,016,182	289,414	1.03E+12	2.94E+11
2000	4,108,556	4	10	-	3,642,214	466,342	6,937,195	6,435,401	501,794	6,937,195	7,403,537	(466,342)		968,137	1,016,182	9.37E+11	9.84E+11
2001	3,210,573	4	10	-	3,645,060	(434,488)	6,914,188	6,424,930	489,259	6,914,188	6,479,700	434,488		54,771	968,137	3.00E+09	5.30E+10
2002	2,572,295	4	10	-	3,647,973	(1,075,677)	6,509,168	6,414,466	94,702	6,509,168	5,433,491	1,075,677		(980,975)	54,771	9.62E+11	-5.37E+10
2003	3,828,164	4	11	-	3,650,354	177,810	6,049,582	6,404,085	(354,503)	6,049,582	6,227,392	(177,810)		(176,693)	(980,975)	3.12E+10	1.73E+11
2004	3,535,823	4	11	-	3,653,691	(117,868)	6,403,477	6,393,607	9,870	6,403,477	6,285,609	117,868		(107,998)	(176,693)	1.17E+10	1.91E+10
													SUM	88,809	107,998	1.94E+13	8.59E+12

ORIGINAL REGRESSION D-W

SLOPE	0.441640573
INTERCEPT	1468.302375
DURBIN-WATSON	1.12
R-SQUARED	0.044

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(88,809)				##########	
1.75E+06	-8.88E+04	1.84E+06	3.39E+12	3.07E+12	-1.56E+11
1.02E+06	1.75E+06	-7.29E+05	5.32E+11	1.05E+12	1.79E+12
-5.96E+05	1.02E+06	-1.62E+06	2.62E+12	3.56E+11	-6.10E+11
1.80E+05	-5.96E+05	7.77E+05	6.03E+11	3.26E+10	-1.08E+11
1.90E+05	1.80E+05	9.99E+03	9.99E+07	3.63E+10	3.44E+10
-4.92E+03	1.90E+05	-1.95E+05	3.82E+10	2.42E+07	-9.37E+08
-1.20E+06	-4.92E+03	-1.19E+06	1.42E+12	1.43E+12	5.89E+09
-1.02E+06	-1.20E+06	1.80E+05	3.24E+10	1.03E+12	1.21E+12
5.75E+05	-1.02E+06	1.59E+06	2.53E+12	3.31E+11	-5.84E+11
-6.96E+05	5.75E+05	-1.27E+06	1.62E+12	4.84E+11	-4.00E+11
-5.98E+05	-6.96E+05	9.83E+04	9.66E+09	3.57E+11	4.16E+11
-1.39E+04	-5.98E+05	5.84E+05	3.41E+11	1.93E+08	8.30E+09
1.32E+05	-1.39E+04	1.46E+05	2.13E+10	1.74E+10	-1.83E+09
1.39E+05	1.32E+05	7.22E+03	5.22E+07	1.94E+10	1.84E+10
-6.75E+05	1.39E+05	-8.14E+05	6.63E+11	4.56E+11	-9.39E+10
-1.36E+06	-6.75E+05	-6.83E+05	4.67E+11	1.84E+12	9.17E+11
-1.33E+06	-1.36E+06	3.10E+04	9.62E+08	1.76E+12	1.80E+12
-6.05E+05	-1.33E+06	7.22E+05	5.21E+11	3.66E+11	8.03E+11
9.07E+05	-6.05E+05	1.51E+06	2.29E+12	8.22E+11	-5.49E+11
1.59E+06	9.07E+05	6.87E+05	4.72E+11	2.54E+12	1.44E+12
6.18E+05	1.59E+06	-9.76E+05	9.52E+11	3.81E+11	9.84E+11
2.89E+05	6.18E+05	-3.28E+05	1.08E+11	8.38E+10	1.79E+11
1.02E+06	2.89E+05	7.27E+05	5.28E+11	1.03E+12	2.94E+11
9.68E+05	1.02E+06	-4.80E+04	2.31E+09	9.37E+11	9.84E+11
5.48E+04	9.68E+05	-9.13E+05	8.34E+11	3.00E+09	5.30E+10
-9.81E+05	5.48E+04	-1.04E+06	1.07E+12	9.62E+11	-5.37E+10
-1.77E+05	-9.81E+05	8.04E+05	6.47E+11	3.12E+10	1.73E+11
-1.08E+05	-1.77E+05	6.87E+04	4.72E+09	1.17E+10	1.91E+10
8.88E+04	1.08E+05	-1.92E+04	2.17E+13	1.95E+13	8.59E+12

TRANSFORMED REGRESSION D-W

SLOPE	0.11500648
INTERCEPT	-563.935479
DURBIN-WATSON	1.77
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1.67E+03				2.79E+06	
5.27E+05	1.67E+03	5.26E+05	2.76E+11	2.78E+11	8.81E+08
-8.02E+05	5.27E+05	-1.33E+06	1.77E+12	6.43E+11	-4.23E+11
6.83E+05	-8.02E+05	1.48E+06	2.20E+12	4.67E+11	-5.48E+11
3.35E+05	6.83E+05	-3.48E+05	1.21E+11	1.12E+11	2.29E+11
1.09E+05	3.35E+05	-2.26E+05	5.10E+10	1.19E+10	3.65E+10
-1.00E+06	1.09E+05	-1.11E+06	1.23E+12	1.00E+12	-1.09E+11
-3.15E+05	-1.00E+06	6.85E+05	4.69E+11	9.93E+10	3.15E+11
1.17E+06	-3.15E+05	1.48E+06	2.20E+12	1.37E+12	-3.68E+11
-8.26E+05	1.17E+06	-2.00E+06	3.98E+12	6.82E+11	-9.66E+11
-1.91E+05	-8.26E+05	6.35E+05	4.04E+11	3.63E+10	1.57E+11
3.36E+05	-1.91E+05	5.27E+05	2.78E+11	1.13E+11	-6.41E+10
2.13E+05	3.36E+05	-1.24E+05	1.53E+10	4.53E+10	7.16E+10
1.41E+05	2.13E+05	-7.23E+04	5.23E+09	1.98E+10	2.99E+10
-6.91E+05	1.41E+05	-8.32E+05	6.92E+11	4.78E+11	-9.71E+10
-1.03E+06	-6.91E+05	-3.34E+05	1.12E+11	1.05E+12	7.08E+11
-7.21E+05	-1.03E+06	3.04E+05	9.23E+10	5.20E+11	7.39E+11
-1.72E+04	-7.21E+05	7.04E+05	4.96E+11	2.94E+08	1.24E+10
1.17E+06	-1.72E+04	1.18E+06	1.40E+12	1.36E+12	-2.00E+10
1.18E+06	1.17E+06	1.01E+04	1.02E+08	1.38E+12	1.37E+12
-1.11E+05	1.18E+06	-1.29E+06	1.66E+12	1.24E+10	-1.31E+11
-1.87E+04	-1.11E+05	9.27E+04	8.60E+09	3.52E+08	2.09E+09
8.44E+05	-1.87E+04	8.63E+05	7.44E+11	7.12E+11	-1.58E+10
4.66E+05	8.44E+05	-3.78E+05	1.43E+11	2.17E+11	3.94E+11
-4.34E+05	4.66E+05	-9.01E+05	8.11E+11	1.89E+11	-2.03E+11
-1.08E+06	-4.34E+05	-6.41E+05	4.11E+11	1.16E+12	4.67E+11
1.78E+05	-1.08E+06	1.25E+06	1.57E+12	3.16E+10	-1.91E+11
-1.18E+05	1.78E+05	-2.96E+05	8.74E+10	1.39E+10	-2.10E+10
7.73E-08	1.18E+05	-1.20E+05	2.12E+13	1.20E+13	1.38E+12

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2E - Ln Distribution Capacity-Related Expenses - Ln(Year) and Ln(Plt Investment)

R SQUARED, ADJUSTED = 0.04
DURBIN WATSON STATISTIC = 1.10

		Before Cochrane Orcott Adjustment	
DPETC =	Distr Expense Total Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		37	0.748
LN(YEAR) =	Ln(Year)	(3)	-0.426
LN(DTI) =	Ln Distr Plant Invest	-0.27%	-0.7137

Line Estimate Results

-2.72E-03	(3)	3.66E+01	#N/A
3.82E-03	6	4.90E+01	#N/A
0.043055	0	#N/A	#N/A
0.5849	26	#N/A	#N/A
2.03E-02	4.52E-01	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid
YEAR	DPETC	LN(YEAR)	LN(DTI)

YEAR	DISTR EXPENSE TOTAL COST	LN(YEAR)	LN DISTR PLANT INVEST	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	15.80	7.59	(21)	15.81	(0.01)	15.80
1977	15.95	7.59	15.27	15.71	0.24	15.95
1978	15.86	7.59	15.98	15.71	0.15	15.86
1979	15.62	7.59	16.47	15.71	(0.08)	15.62
1980	15.74	7.59	16.68	15.70	0.04	15.74
1981	15.74	7.59	16.84	15.70	0.04	15.74
1982	15.71	7.59	17.04	15.70	0.01	15.71
1983	15.51	7.59	17.11	15.70	(0.19)	15.51
1984	15.54	7.59	17.24	15.70	(0.16)	15.54
1985	15.79	7.59	17.44	15.70	0.09	15.79
1986	15.59	7.59	17.63	15.69	(0.10)	15.59
1987	15.60	7.59	17.84	15.69	(0.09)	15.60
1988	15.70	7.59	17.98	15.69	0.01	15.70
1989	15.72	7.60	18.07	15.69	0.03	15.72
1990	15.72	7.60	18.17	15.69	0.03	15.72
1991	15.58	7.60	18.26	15.68	(0.10)	15.58
1992	15.46	7.60	18.32	15.68	(0.23)	15.46
1993	15.46	7.60	18.51	15.68	(0.22)	15.46
1994	15.59	7.60	18.57	15.68	(0.09)	15.59
1995	15.82	7.60	18.61	15.68	0.14	15.82
1996	15.90	7.60	18.64	15.68	0.23	15.90
1997	15.77	7.60	18.67	15.68	0.10	15.77
1998	15.72	7.60	18.70	15.67	0.05	15.72
1999	15.83	7.60	18.72	15.67	0.15	15.83
2000	15.82	7.60	18.75	15.67	0.15	15.82
2001	15.68	7.60	18.76	15.67	0.01	15.68
2002	15.51	7.60	18.78	15.67	(0.16)	15.51
2003	15.64	7.60	18.80	15.67	(0.02)	15.64
2004	15.65	7.60	18.82	15.67	(0.01)	15.65

REGRESSION MODEL NO. 2E - Ln Distribution Capacity-Related Expenses - Ln(Year) and Ln(Plt Investment) WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =	0.15
DURBIN WATSON STATISTIC =	1.76

After Cochrane Orcott Adjustment

X-VARIABLE COEFF.	t STATISTIC
4	0.109
1	0.109
1.58%	2.079

Line Estimate Results

1.58E-02	1	4.25E+00	#N/A
7.62E-03	9	3.90E+01	#N/A
0.149815	0	#N/A	#N/A
2.2027	25	#N/A	#N/A
5.14E-02	2.92E-01	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

	TRANSFORMED VARIABLES										ORIGINAL		RHO	0.44763		
	Y	X1	X2	X3	ESTIMATED		ADJUSTED FORECAST	ORIGINAL FORECAST		ADJUSTED FORECAST	ESTIMATED + RESIDUAL					
YEAR	TOTAL COST	LN(YEAR)	N/A	N/A	(Y)'t	RESIDUAL	(Y)	(Y)'	DIFFERENCE	(Y)	(Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2	E(t)*E(t-1)
1976													(0)			
1977	8.88	4.19	24.54	-	8.88	0.00	15.95	15.71	0.24	15.95	15.95	(0.00)	0.24	(0.01)	0.06	(0.00)
1978	8.72	4.19	9.15	-	8.64	0.08	15.78	15.71	0.07	15.78	15.86	(0.08)	0.15	0.24	0.02	0.04
1979	8.52	4.19	9.31	-	8.64	(0.12)	15.74	15.71	0.03	15.74	15.62	0.12	(0.08)	0.15	0.01	(0.01)
1980	8.75	4.19	9.31	-	8.64	0.11	15.63	15.70	(0.07)	15.63	15.74	(0.11)	0.04	(0.08)	0.00	(0.00)
1981	8.69	4.19	9.37	-	8.64	0.05	15.69	15.70	(0.01)	15.69	15.74	(0.05)	0.04	0.04	0.00	0.00
1982	8.66	4.19	9.50	-	8.64	0.02	15.69	15.70	(0.01)	15.69	15.71	(0.02)	0.01	0.04	0.00	0.00
1983	8.48	4.19	9.48	-	8.64	(0.17)	15.68	15.70	(0.02)	15.68	15.51	0.17	(0.19)	0.01	0.04	(0.00)
1984	8.60	4.19	9.58	-	8.65	(0.05)	15.59	15.70	(0.11)	15.59	15.54	0.05	(0.16)	(0.19)	0.02	0.03
1985	8.83	4.19	9.72	-	8.65	0.18	15.60	15.70	(0.09)	15.60	15.79	(0.18)	0.09	(0.16)	0.01	(0.01)
1986	8.52	4.19	9.83	-	8.65	(0.13)	15.72	15.69	0.02	15.72	15.59	0.13	(0.10)	0.09	0.01	(0.01)
1987	8.63	4.20	9.95	-	8.65	(0.03)	15.63	15.69	(0.06)	15.63	15.60	0.03	(0.09)	(0.10)	0.01	0.01
1988	8.71	4.20	9.99	-	8.65	0.06	15.64	15.69	(0.05)	15.64	15.70	(0.06)	0.01	(0.09)	0.00	(0.00)
1989	8.69	4.20	10.02	-	8.65	0.04	15.68	15.69	(0.01)	15.68	15.72	(0.04)	0.03	0.01	0.00	0.00
1990	8.68	4.20	10.08	-	8.66	0.02	15.69	15.69	0.00	15.69	15.72	(0.02)	0.03	0.03	0.00	0.00
1991	8.55	4.20	10.13	-	8.66	(0.11)	15.69	15.68	0.01	15.69	15.58	0.11	(0.10)	0.03	0.01	(0.00)
1992	8.48	4.20	10.15	-	8.66	(0.18)	15.63	15.68	(0.05)	15.63	15.46	0.18	(0.23)	(0.10)	0.05	0.02
1993	8.54	4.20	10.31	-	8.66	(0.12)	15.58	15.68	(0.10)	15.58	15.46	0.12	(0.22)	(0.23)	0.05	0.05
1994	8.67	4.20	10.28	-	8.66	0.01	15.58	15.68	(0.10)	15.58	15.59	(0.01)	(0.09)	(0.22)	0.01	0.02
1995	8.84	4.20	10.30	-	8.66	0.18	15.64	15.68	(0.04)	15.64	15.82	(0.18)	0.14	(0.09)	0.02	(0.01)
1996	8.82	4.20	10.31	-	8.66	0.16	15.74	15.68	0.06	15.74	15.90	(0.16)	0.23	0.14	0.05	0.03
1997	8.65	4.20	10.32	-	8.66	(0.01)	15.78	15.68	0.11	15.78	15.77	0.01	0.10	0.23	0.01	0.02
1998	8.66	4.20	10.34	-	8.66	0.00	15.72	15.67	0.05	15.72	15.72	(0.00)	0.05	0.10	0.00	0.00
1999	8.79	4.20	10.35	-	8.66	0.12	15.70	15.67	0.03	15.70	15.83	(0.12)	0.15	0.05	0.02	0.01
2000	8.73	4.20	10.36	-	8.66	0.07	15.75	15.67	0.08	15.75	15.82	(0.07)	0.15	0.15	0.02	0.02
2001	8.60	4.20	10.37	-	8.66	(0.06)	15.74	15.67	0.07	15.74	15.68	0.06	0.01	0.15	0.00	0.00
2002	8.49	4.20	10.38	-	8.66	(0.18)	15.68	15.67	0.02	15.68	15.51	0.18	(0.16)	0.01	0.03	(0.00)
2003	8.70	4.20	10.39	-	8.66	0.04	15.61	15.67	(0.06)	15.61	15.64	(0.04)	(0.02)	(0.16)	0.00	0.00
2004	8.65	4.20	10.40	-	8.66	(0.01)	15.67	15.67	0.00	15.67	15.65	0.01	(0.01)	(0.02)	0.00	0.00
												SU	0.01	0.01	0.45	0.20

ORIGINAL REGRESSION D-W

SLOPE	0.447592227
INTERCEPT	0.000275348
DURBIN-WATSON	1.10
R-SQUARED	0.043

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(0)				0	
0.24	(0.01)	0.25	0.06	0.06	(0.00)
0.15	0.24	(0.09)	0.01	0.02	0.04
(0.08)	0.15	(0.24)	0.06	0.01	(0.01)
0.04	(0.08)	0.12	0.01	0.00	(0.00)
0.04	0.04	0.00	0.00	0.00	0.00
0.01	0.04	(0.03)	0.00	0.00	0.00
(0.19)	0.01	(0.20)	0.04	0.04	(0.00)
(0.16)	(0.19)	0.03	0.00	0.02	0.03
0.09	(0.16)	0.25	0.06	0.01	(0.01)
(0.10)	0.09	(0.20)	0.04	0.01	(0.01)
(0.09)	(0.10)	0.02	0.00	0.01	0.01
0.01	(0.09)	0.09	0.01	0.00	(0.00)
0.03	0.01	0.02	0.00	0.00	0.00
0.03	0.03	0.00	0.00	0.00	0.00
(0.10)	0.03	(0.13)	0.02	0.01	(0.00)
(0.23)	(0.10)	(0.12)	0.02	0.05	0.02
(0.22)	(0.23)	0.01	0.00	0.05	0.05
(0.09)	(0.22)	0.13	0.02	0.01	0.02
0.14	(0.09)	0.23	0.05	0.02	(0.01)
0.23	0.14	0.09	0.01	0.05	0.03
0.10	0.23	(0.13)	0.02	0.01	0.02
0.05	0.10	(0.05)	0.00	0.00	0.00
0.15	0.05	0.10	0.01	0.02	0.01
0.15	0.15	(0.01)	0.00	0.02	0.02
0.01	0.15	(0.13)	0.02	0.00	0.00
(0.16)	0.01	(0.17)	0.03	0.03	(0.00)
(0.02)	(0.16)	0.14	0.02	0.00	0.00
(0.01)	(0.02)	0.01	0.00	0.00	0.00
0.01	0.01	0.00	0.50	0.45	0.20

TRANSFORMED REGRESSION D-W

SLOPE	0.12095697
INTERCEPT	-7.78763E-05
DURBIN-WATSON	1.76
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
0.00				0.00	
0.08	0.00	0.08	0.01	0.01	0.00
(0.12)	0.08	(0.20)	0.04	0.01	(0.01)
0.11	(0.12)	0.22	0.05	0.01	(0.01)
0.05	0.11	(0.05)	0.00	0.00	0.01
0.02	0.05	(0.03)	0.00	0.00	0.00
(0.17)	0.02	(0.19)	0.03	0.03	(0.00)
(0.05)	(0.17)	0.12	0.01	0.00	0.01
0.18	(0.05)	0.23	0.05	0.03	(0.01)
(0.13)	0.18	(0.31)	0.10	0.02	(0.02)
(0.03)	(0.13)	0.10	0.01	0.00	0.00
0.06	(0.03)	0.08	0.01	0.00	(0.00)
0.04	0.06	(0.02)	0.00	0.00	0.00
0.02	0.04	(0.01)	0.00	0.00	0.00
(0.11)	0.02	(0.13)	0.02	0.01	(0.00)
(0.18)	(0.11)	(0.07)	0.00	0.03	0.02
(0.12)	(0.18)	0.06	0.00	0.01	0.02
0.01	(0.12)	0.13	0.02	0.00	(0.00)
0.18	0.01	0.17	0.03	0.03	0.00
0.16	0.18	(0.01)	0.00	0.03	0.03
(0.01)	0.16	(0.17)	0.03	0.00	(0.00)
0.00	(0.01)	0.01	0.00	0.00	(0.00)
0.12	0.00	0.12	0.01	0.02	0.00
0.07	0.12	(0.05)	0.00	0.00	0.01
(0.06)	0.07	(0.13)	0.02	0.00	(0.00)
(0.18)	(0.06)	(0.12)	0.01	0.03	0.01
0.04	(0.18)	0.21	0.05	0.00	(0.01)
(0.01)	0.04	(0.05)	0.00	0.00	(0.00)
(0.00)	0.01	(0.01)	0.51	0.29	0.04

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2G Distribution Capacity-Related Expenses - Year and Design Day Demand

R SQUARED, ADJUSTED = 0.06
DURBIN WATSON STATISTIC = 1.07

DPETC = Distr Expense Total Cost

		Before Cochrane Orcott Adjustment X-VARIABLE COEFF.	t STATISTIC
CONSTANT		199305363	1.184
YEAR =	Year	(98,150)	-1.143
DDD =	Design Day Demand	715.70%	0.9765

Line Estimate Results

7.16E+00	(98,150)	1.99E+08	#N/A
7.33E+00	85,863	1.68E+08	#N/A
0.061217	857,275	#N/A	#N/A
0.8477	26	#N/A	#N/A
1.25E+12	1.91E+13	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

REGRESSION MODEL NO. 2G Distribution Capacity-Related Expenses - Year and Design Day Demand WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.01
DURBIN WATSON STATISTIC = 1.56

After Cochrane Orcott Adjustment X-VARIABLE COEFF.	t STATISTIC
40692306	0.365
(35,174)	-0.332
210.18%	0.251

Line Estimate Results

2.10E+00	(35,174)	4.07E+07	#N/A
8.37E+00	105,803	1.12E+08	#N/A
0.006040	767,475	#N/A	#N/A
0.0760	25	#N/A	#N/A
8.95E+10	1.47E+13	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	DPETC	YEAR	DDD			
YEAR	DISTR EXPENSE TOTAL COST	YEAR	DESIGN DAY DEMAND	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	$7,266,430	1,976	226,225	6980155	286275	7266430
1977	$8,482,448	1,977	221,937	6851317	1631131	8482448
1978	$7,730,844	1,978	231,994	6825147	905697	7730844
1979	$6,092,196	1,979	255,527	6895423	-803227	6092196
1980	$6,854,979	1,980	251,000	6764873	90106	6854979
1981	$6,852,095	1,981	265,000	6766921	85174	6852095
1982	$6,643,007	1,982	283,000	6797597	-154590	6643007
1983	$5,440,661	1,983	261,000	6541993	-1101332	5440661
1984	$5,608,312	1,984	266,366	6482248	-873936	5608312
1985	$7,185,645	1,985	271,605	6421593	764051	7185645
1986	$5,901,049	1,986	292,425	6472452	-571403	5901049
1987	$5,985,548	1,987	307,637	6483175	-497627	5985548
1988	$6,556,706	1,988	317,241	6453761	102946	6556706
1989	$6,690,804	1,989	340,491	6522011	168794	6690804
1990	$6,686,164	1,990	366,674	6611253	74911	6686164
1991	$5,860,228	1,991	377,978	6594006	-733777	5860228
1992	$5,165,797	1,992	387,149	6561492	-1395696	5165797
1993	$5,183,455	1,993	405,800	6596828	-1413372	5183455
1994	$5,894,116	1,994	421,578	6611601	-717485	5894116
1995	$7,395,029	1,995	436,181	6617965	777064	7395029
1996	$8,071,139	1,996	453,181	6641484	1429655	8071139
1997	$7,084,742	1,997	469,409	6659478	425264	7084742
1998	$6,745,913	1,998	477,243	6617396	128518	6745913
1999	$7,462,087	1,999	434,840	6215767	1246320	7462087
2000	$7,403,537	2,000	445,550	6194269	1209268	7403537
2001	$6,479,700	2,001	455,990	6170838	308862	6479700
2002	$5,433,491	2,002	465,290	6139248	-705757	5433491
2003	$6,227,392	2,003	545,890	6617953	-390560	6227392
2004	$6,285,609	2,004	551,630	6560884	-275275	6285609

YEAR	TRANSFORMED VARIABLES Y TOTAL COST	X1 YEAR	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE
1976												
1977	5,118,340	1,062	117,203	-	3,577,861	1,540,479	6,941,969	6,851,317	90,652	6,941,968.9	8,482,448.1	(1,540,479.2)
1978	3,803,762	1,063	129,245	-	3,584,282	219,480	7,511,364	6,825,147	686,217	7,511,364.4	7,730,844.4	(219,480.0)
1979	2,513,080	1,063	148,122	-	3,605,067	(1,091,987)	7,184,183	6,895,423	288,760	7,184,183.0	6,092,195.9	1,091,987.0
1980	4,034,502	1,064	132,700	-	3,553,764	480,737	6,374,242	6,764,873	(390,631)	6,374,242.0	6,854,979.2	(480,737.2)
1981	3,678,475	1,064	148,796	-	3,568,705	109,770	6,742,325	6,766,921	(24,596)	6,742,324.8	6,852,095.2	(109,770.4)
1982	3,470,722	1,065	160,314	-	3,574,024	(103,302)	6,746,309	6,797,597	(51,288)	6,746,309.3	6,643,007.4	103,301.9
1983	2,365,177	1,065	129,981	-	3,491,381	(1,126,204)	6,566,866	6,541,993	24,872	6,566,865.6	5,440,661.2	1,126,204.4
1984	3,089,473	1,066	145,532	-	3,505,177	(415,704)	6,024,016	6,482,248	(458,232)	6,024,016	5,608,312	415,704
1985	4,589,188	1,066	148,287	-	3,492,077	1,097,111	6,088,533	6,421,593	(333,060)	6,088,533	7,185,645	(1,097,111)
1986	2,574,343	1,067	166,681	-	3,511,849	(937,506)	6,838,555	6,472,452	366,103	6,838,555	5,901,049	937,506
1987	3,253,564	1,068	172,254	-	3,504,672	(251,108)	6,236,656	6,483,175	(246,519)	6,236,656	5,985,548	251,108
1988	3,785,603	1,068	174,816	-	3,491,166	294,437	6,262,270	6,453,761	(191,491)	6,262,270	6,556,706	(294,437)
1989	3,655,274	1,069	193,619	-	3,511,798	143,476	6,547,328	6,522,011	25,317	6,547,328	6,690,804	(143,476)
1990	3,588,551	1,069	209,038	-	3,525,316	63,235	6,622,929	6,611,253	11,676	6,622,929	6,686,164	(63,235)
1991	2,764,764	1,070	208,221	-	3,504,707	(739,943)	6,600,172	6,594,006	6,166	6,600,172	5,860,228	739,943
1992	2,452,712	1,070	212,158	-	3,494,094	(1,041,382)	6,207,178	6,561,492	(354,314)	6,207,178	5,165,797	1,041,382
1993	2,791,869	1,071	226,563	-	3,505,481	(713,612)	5,897,067	6,596,828	(699,760)	5,897,067	5,183,455	713,612
1994	3,494,354	1,071	233,707	-	3,501,605	(7,250)	5,901,366	6,611,601	(710,234)	5,901,366	5,894,116	7,250
1995	4,666,255	1,072	241,005	-	3,498,054	1,168,201	6,226,828	6,617,965	(391,137)	6,226,828	7,395,029	(1,168,201)
1996	4,647,494	1,072	251,244	-	3,500,686	1,146,808	6,924,330	6,641,484	282,846	6,924,330	8,071,139	(1,146,808)
1997	3,348,082	1,073	259,602	-	3,499,362	(151,280)	7,236,022	6,659,478	576,544	7,236,022	7,084,742	151,280
1998	3,465,921	1,073	259,923	-	3,481,147	(15,226)	6,761,140	6,617,396	143,744	6,761,140	6,745,913	15,226
1999	4,338,961	1,074	213,893	-	3,365,513	973,447	6,488,640	6,215,767	272,873	6,488,640	7,462,087	(973,447)
2000	3,948,847	1,075	244,234	-	3,410,394	538,453	6,865,084	6,194,269	670,815	6,865,084	7,403,537	(538,453)
2001	3,052,117	1,075	249,716	-	3,403,026	(350,909)	6,830,609	6,170,838	659,771	6,830,609	6,479,700	350,909
2002	2,433,612	1,076	254,182	-	3,393,524	(959,912)	6,393,403	6,139,248	254,155	6,393,403	5,433,491	959,912
2003	3,711,872	1,076	330,477	-	3,534,988	176,884	6,050,508	6,617,953	(567,445)	6,050,508	6,227,392	(176,884)
2004	3,402,540	1,077	298,902	-	3,449,735	(47,195)	6,332,804	6,560,884	(228,080)	6,332,804	6,285,609	47,195

RHO 0.46297

	ERROR	LAGGED ERROR	ERROR^2	E(t)*E(t-1)
	286,275			
	1,631,131	286,275	2.66E+12	4.67E+11
	905,697	1,631,131	8.20E+11	1.48E+12
	(803,227)	905,697	6.45E+11	-7.27E+11
	90,106	(803,227)	8.12E+09	-7.24E+10
	85,174	90,106	7.25E+09	7.67E+09
	(154,590)	85,174	2.39E+10	-1.32E+10
	(1,101,332)	(154,590)	1.21E+12	1.70E+11
	(873,936)	(1,101,332)	7.64E+11	9.62E+11
	764,051	(873,936)	5.84E+11	-6.68E+11
	(571,403)	764,051	3.27E+11	-4.37E+11
	(497,627)	(571,403)	2.48E+11	2.84E+11
	102,946	(497,627)	1.06E+10	-5.12E+10
	168,794	102,946	2.85E+10	1.74E+10
	74,911	168,794	5.61E+09	1.26E+10
	(733,777)	74,911	5.38E+11	-5.50E+10
	(1,395,696)	(733,777)	1.95E+12	1.02E+12
	(1,413,372)	(1,395,696)	2.00E+12	1.97E+12
	(717,485)	(1,413,372)	5.15E+11	1.01E+12
	777,064	(717,485)	6.04E+11	-5.58E+11
	1,429,655	777,064	2.04E+12	1.11E+12
	425,264	1,429,655	1.81E+11	6.08E+11
	128,518	425,264	1.65E+10	5.47E+10
	1,246,320	128,518	1.55E+12	1.60E+11
	1,209,268	1,246,320	1.46E+12	1.51E+12
	308,862	1,209,268	9.54E+10	3.73E+11
	(705,757)	308,862	4.98E+11	-2.18E+11
	(390,560)	(705,757)	1.53E+11	2.76E+11
	(275,275)	(390,560)	7.58E+10	1.08E+11
SUM	(286,275)	275,275	1.90E+13	8.81E+12

ORIGINAL REGRESSION D-W
SLOPE 0.463029137
INTERCEPT -14776.273
DURBIN-WATSON 1.07
R-SQUARED 0.061

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
286,275				#########	
1.63E+06	2.86E+05	1.34E+06	1.81E+12	2.66E+12	4.67E+11
9.06E+05	1.63E+06	-7.25E+05	5.26E+11	8.20E+11	1.48E+12
-8.03E+05	9.06E+05	-1.71E+06	2.92E+12	6.45E+11	-7.27E+11
9.01E+04	-8.03E+05	8.93E+05	7.98E+11	8.12E+09	-7.24E+10
8.52E+04	9.01E+04	-4.93E+03	2.43E+07	7.25E+09	7.67E+09
-1.55E+05	8.52E+04	-2.40E+05	5.75E+10	2.39E+10	-1.32E+10
-1.10E+06	-1.55E+05	-9.47E+05	8.96E+11	1.21E+12	1.70E+11
-8.74E+05	-1.10E+06	2.27E+05	5.17E+10	7.64E+11	9.62E+11
7.64E+05	-8.74E+05	1.64E+06	2.68E+12	5.84E+11	-6.68E+11
-5.71E+05	7.64E+05	-1.34E+06	1.78E+12	3.27E+11	-4.37E+11
-4.98E+05	-5.71E+05	7.38E+04	5.44E+09	2.48E+11	2.84E+11
1.03E+05	-4.98E+05	6.01E+05	3.61E+11	1.06E+10	-5.12E+10
1.69E+05	1.03E+05	6.58E+04	4.34E+09	2.85E+10	1.74E+10
7.49E+04	1.69E+05	-9.39E+04	8.81E+09	5.61E+09	1.26E+10
-7.34E+05	7.49E+04	-8.09E+05	6.54E+11	5.38E+11	-5.50E+10
-1.40E+06	-7.34E+05	-6.62E+05	4.38E+11	1.95E+12	1.02E+12
-1.41E+06	-1.40E+06	-1.77E+04	3.12E+08	2.00E+12	1.97E+12
-7.17E+05	-1.41E+06	6.96E+05	4.84E+11	5.15E+11	1.01E+12
7.77E+05	-7.17E+05	1.49E+06	2.23E+12	6.04E+11	-5.58E+11
1.43E+06	7.77E+05	6.53E+05	4.26E+11	2.04E+12	1.11E+12
4.25E+05	1.43E+06	-1.00E+06	1.01E+12	1.81E+11	6.08E+11
1.29E+05	4.25E+05	-2.97E+05	8.81E+10	1.65E+10	5.47E+10
1.25E+06	1.29E+05	1.12E+06	1.25E+12	1.55E+12	1.60E+11
1.21E+06	1.25E+06	-3.71E+04	1.37E+09	1.46E+12	1.51E+12
3.09E+05	1.21E+06	-9.00E+05	8.11E+11	9.54E+10	3.73E+11
-7.06E+05	3.09E+05	-1.01E+06	1.03E+12	4.98E+11	-2.18E+11
-3.91E+05	-7.06E+05	3.15E+05	9.93E+10	1.53E+11	2.76E+11
-2.75E+05	-3.91E+05	1.15E+05	1.33E+10	7.58E+10	1.08E+11
-2.86E+05	2.75E+05	-5.62E+05	2.04E+13	1.91E+13	8.81E+12

TRANSFORMED REGRESSION D-W
SLOPE 0.138659653
INTERCEPT -57297.1555
DURBIN-WATSON 1.56
R-SQUARED

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1.54E+06				2.37E+12	
2.19E+05	1.54E+06	-1.32E+06	1.75E+12	4.82E+10	3.38E+11
-1.09E+06	2.19E+05	-1.31E+06	1.72E+12	1.19E+12	-2.40E+11
4.81E+05	-1.09E+06	1.57E+06	2.47E+12	2.31E+11	-5.25E+11
1.10E+05	4.81E+05	-3.71E+05	1.38E+11	1.20E+10	5.28E+10
-1.03E+05	1.10E+05	-2.13E+05	4.54E+10	1.07E+10	-1.13E+10
-1.13E+06	-1.03E+05	-1.02E+06	1.05E+12	1.27E+12	1.16E+11
-4.16E+05	-1.13E+06	7.11E+05	5.05E+11	1.73E+11	4.68E+11
1.10E+06	-4.16E+05	1.51E+06	2.29E+12	1.20E+12	-4.56E+11
-9.38E+05	1.10E+06	-2.03E+06	4.14E+12	8.79E+11	-1.03E+12
-2.51E+05	-9.38E+05	6.86E+05	4.71E+11	6.31E+10	2.35E+11
2.94E+05	-2.51E+05	5.46E+05	2.98E+11	8.67E+10	-7.39E+10
1.43E+05	2.94E+05	-1.51E+05	2.28E+10	2.06E+10	4.22E+10
6.32E+04	1.43E+05	-8.02E+04	6.44E+09	4.00E+09	9.07E+09
-7.40E+05	6.32E+04	-8.03E+05	6.45E+11	5.48E+11	-4.68E+10
-1.04E+06	-7.40E+05	-3.01E+05	9.09E+10	1.08E+12	7.71E+11
-7.14E+05	-1.04E+06	3.28E+05	1.07E+11	5.09E+11	7.43E+11
-7.25E+03	-7.14E+05	7.06E+05	4.99E+11	5.26E+07	5.17E+09
1.17E+06	-7.25E+03	1.18E+06	1.38E+12	1.36E+12	-8.47E+09
1.15E+06	1.17E+06	-2.14E+04	4.58E+08	1.32E+12	1.34E+12
-1.51E+05	1.15E+06	-1.30E+06	1.69E+12	2.29E+10	-1.73E+11
-1.52E+04	-1.51E+05	1.36E+05	1.85E+10	2.32E+08	2.30E+09
9.73E+05	-1.52E+04	9.89E+05	9.77E+11	9.48E+11	-1.48E+10
5.38E+05	9.73E+05	-4.35E+05	1.89E+11	2.90E+11	5.24E+11
-3.51E+05	5.38E+05	-8.89E+05	7.91E+11	1.23E+11	-1.89E+11
-9.60E+05	-3.51E+05	-6.09E+05	3.71E+11	9.21E+11	3.37E+11
1.77E+05	-9.60E+05	1.14E+06	1.29E+12	3.13E+10	-1.70E+11
-4.72E+04	1.77E+05	-2.24E+05	5.02E+10	2.23E+09	-8.35E+09
-4.19E-09	4.72E+04	-1.59E+06	2.30E+13	1.47E+13	2.04E+12

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 2B IT Distribution Capacity-Related Expens

R SQUARED, ADJUSTED = 0.87
DURBIN WATSON STATISTIC = 0.86

		Before Cochrane Orcott Adjustment	
DPEUC =	Dist Plt Expense Unit Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		1299	13.660
YEAR =	Year	$ (0.64292)	-13.459
DTI =	Distr Plant Invest		

Line Estimate Results

(0.64292)	1,299	#N/A	#N/A
0.047770	95	#N/A	#N/A
0.870275	2	#N/A	#N/A
181.1322	27	#N/A	#N/A
8.39E+02	1.25E+02	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	DPEUC	YEAR	DTI			
YEAR	DIST PLT EXPENSE UNIT COST	YEAR	DISTR PLANT INVEST	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	$23.27	1,976	-	28	-5	23
1977	$24.88	1,977	4,271,252	28	-3	25
1978	$25.94	1,978	8,709,537	27	-1	26
1979	$29.27	1,979	14,171,669	26	3	29
1980	$29.96	1,980	17,555,811	26	4	30
1981	$27.64	1,981	20,482,450	25	3	28
1982	$22.45	1,982	25,131,748	24	-2	22
1983	$22.18	1,983	26,864,548	24	-2	22
1984	$23.32	1,984	30,623,182	23	0	23
1985	$23.99	1,985	37,471,980	22	2	24
1986	$21.89	1,986	45,457,524	22	0	22
1987	$23.42	1,987	56,022,555	21	2	23
1988	$23.44	1,988	64,157,785	20	3	23
1989	$20.92	1,989	70,317,222	20	1	21
1990	$20.02	1,990	77,529,058	19	1	20
1991	$17.72	1,991	85,179,871	19	-1	18
1992	$17.54	1,992	90,741,028	18	0	18
1993	$15.19	1,993	109,280,404	17	-2	15
1994	$15.05	1,994	115,788,625	17	-2	15
1995	$13.64	1,995	120,821,863	16	-2	14
1996	$14.76	1,996	124,794,681	15	-1	15
1997	$11.14	1,997	127,968,212	15	-4	11
1998	$14.21	1,998	131,965,544	14	0	14
1999	$15.61	1,999	135,453,840	13	2	16
2000	$13.64	2,000	138,343,843	13	1	14
2001	$12.23	2,001	141,063,792	12	0	12
2002	$11.30	2,002	143,813,174	11	0	11
2003	$10.23	2,003	145,956,482	11	-1	10
2004	$11.36	2,004	149,025,071	10	1	11

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REGRESSION MODEL NO. 2B IT Distribution Capacity-Related Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =		0.70
DURBIN WATSON STATISTIC =		1.87

After Cochrane Orcott Adjustment

	X-VARIABLE COEFF.	t STATISTIC
	612	7.925
$	(0.72291)	-7.825

Line Estimate Results

(0.72291)	612	#N/A	#N/A
0.092386	77	#N/A	#N/A
0.701932	2	#N/A	#N/A
61.2283	26	#N/A	#N/A
168	71	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

RHO 0.58027

YEAR	Y UNIT COST	X1 YEAR	X2 N/A (TRANSFORMED VARIABLES)	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2
1976													(5)		
1977	11	830	4,271,252	-	12	(0)	25	28	(2)	25.3	24.9	0.5	(3)	(5)	7
1978	11	831	6,231,042	-	12	(0)	26	27	(1)	26.0	25.9	0.0	(1)	(3)	1
1979	14	831	9,117,755	-	11	3	26	26	0	26.3	29.3	(3.0)	3	(1)	9
1980	13	832	9,332,366	-	11	2	28	26	2	27.9	30.0	(2.0)	4	3	19
1981	10	832	#########	-	11	(0)	28	25	3	28.0	27.6	0.4	3	4	7
1982	6	832	#########	-	10	(4)	26	24	2	26.4	22.5	3.9	(2)	3	3
1983	9	833	#########	-	10	(1)	23	24	(1)	23.0	22.2	0.9	(2)	(2)	2
1984	10	833	#########	-	10	1	23	23	(0)	23	23	(1)	0	(2)	0
1985	10	834	#########	-	9	1	23	22	1	23	24	(1)	2	0	3
1986	8	834	#########	-	9	(1)	23	22	1	23	22	1	0	2	0
1987	11	835	#########	-	9	2	22	21	0	22	23	(2)	2	0	5
1988	10	835	#########	-	9	1	22	20	2	22	23	(1)	3	2	9
1989	7	835	#########	-	8	(1)	22	20	2	22	21	1	1	3	1
1990	8	836	#########	-	8	(0)	20	19	1	20	20	0	1	1	1
1991	6	836	#########	-	8	(1)	19	19	1	19	18	1	(1)	1	1
1992	7	837	#########	-	7	(0)	18	18	(0)	18	18	0	(0)	(1)	0
1993	5	837	#########	-	7	(2)	17	17	(0)	17	15	2	(2)	(0)	4
1994	6	838	#########	-	7	(0)	15	17	(1)	15	15	0	(2)	(2)	2
1995	5	838	#########	-	6	(1)	15	16	(1)	15	14	1	(2)	(2)	5
1996	7	838	#########	-	6	1	14	15	(1)	14	15	(1)	(1)	(2)	0
1997	3	839	#########	-	6	(3)	14	15	(0)	14	11	3	(4)	(1)	13
1998	8	839	#########	-	5	2	12	14	(2)	12	14	(2)	0	(4)	0
1999	7	840	#########	-	5	2	13	13	0	13	16	(2)	2	0	5
2000	5	840	#########	-	5	(0)	14	13	1	14	14	0	1	2	1
2001	4	840	#########	-	5	(0)	12	12	0	12	12	0	0	1	0
2002	4	841	#########	-	4	(0)	11	11	(0)	11	11	0	(0)	0	0
2003	4	841	#########	-	4	(0)	11	11	(0)	11	10	0	(1)	(0)	0
2004	5	842	#########	-	4	2	10	10	(1)	10	11	(2)	1	(1)	1
												SUM	5	(1)	101

E(t)*E(t-1)
13
3
(3)
13
12
(5)
3
(0)
0
0
0
7
3
1
(1)
0
1
3
4
1
2
(1)
0
2
0
(0)
0
(1)
59

ORIGINAL REGRESSION D-W

SLOPE	0.47534743
INTERCEPT	0.195542711
DURBIN-WATSON	0.86
R-SQUARED	0.870

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(5)				24	
(3)	(5)	2	5	7	13
(1)	(3)	2	3	1	3
3	(1)	4	16	9	(3)
4	3	1	2	19	13
3	4	(2)	3	7	12
(2)	3	(5)	21	3	(5)
(2)	(2)	0	0	2	3
0	(2)	2	3	0	(0)
2	0	1	2	3	0
0	2	(1)	2	0	0
2	0	2	5	5	0
3	2	1	0	9	7
1	3	(2)	4	1	3
1	1	(0)	0	1	1
(1)	1	(2)	3	1	(1)
(0)	(1)	0	0	0	0
(2)	(0)	(2)	3	4	1
(2)	(2)	1	0	2	3
(2)	(2)	(1)	1	5	4
(1)	(2)	2	3	0	1
(4)	(1)	(3)	9	13	2
0	(4)	4	14	0	(1)
2	0	2	4	5	0
1	2	(1)	2	1	2
0	1	(1)	1	0	0
(0)	0	(0)	0	0	(0)
(1)	(0)	(0)	0	0	0
1	(1)	2	3	1	(1)
5	(1)	6	107	125	59

TRANSFORMED REGRESSION D-W

SLOPE	0.044296115
INTERCEPT	0.019761804
DURBIN-WATSON	1.87
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(0)				0	
(0)	(0)	0	0	0	0
3	(0)	3	9	9	(0)
2	3	(1)	1	4	6
(0)	2	(2)	6	0	(1)
(4)	(0)	(4)	13	15	1
(1)	(4)	3	9	1	3
1	(1)	2	3	1	(1)
1	1	0	0	1	1
(1)	1	(2)	5	1	(1)
2	(1)	3	9	4	(2)
1	2	(1)	0	2	3
(1)	1	(2)	5	1	(1)
(0)	(1)	1	1	0	0
(1)	(0)	(1)	2	2	0
(0)	(1)	1	2	0	0
(2)	(0)	(2)	4	4	0
(0)	(2)	2	2	0	1
(1)	(0)	(1)	1	2	1
1	(1)	2	5	1	(1)
(3)	1	(4)	16	10	(2)
2	(3)	5	30	5	(7)
2	2	(0)	0	5	5
(0)	2	(2)	6	0	(1)
(0)	(0)	0	0	0	0
(0)	(0)	0	0	0	0
(0)	(0)	(0)	0	0	0
2	(0)	2	4	3	(0)
0	(2)	2	134	71	3

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 3 Distribution Plant Customer-Related E

R SQUARED, ADJUSTED = 0.55
DURBIN WATSON STATISTIC = 0.66

Before Cochrane Orcott Adjustment

			X-VARIABLE COEFF.	t STATISTIC
DPCE =	Dist Plt Customer Expense			
CONSTANT			1347044	0.694
CUST =	Cust'S	$	47.51	5.759
=				

Line Estimate Results

47.51071	1,347,044	#N/A	#N/A
8.249451	1,942,321	#N/A	#N/A
0.551264	1,547,297	#N/A	#N/A
33.1690	27	#N/A	#N/A
7.94E+13	6.46E+13	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	DPCE	CUST			
YEAR	DIST PLT CUSTOMER EXPENSE	CUST'S	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	10,828,301	184,779	10126025	702276	10828301
1977	10,910,322	184,321	10104265	806057	10910322
1978	11,417,876	185,232	10147547	1270329	11417876
1979	12,227,701	189,091	10330891	1896810	12227701
1980	12,233,364	192,620	10498557	1734808	12233364
1981	11,328,172	194,544	10589967	738205	11328172
1982	9,685,672	195,276	10624745	-939073	9685672
1983	9,347,447	197,836	10746372	-1398925	9347447
1984	10,446,628	195,276	10624745	-178117	10446628
1985	10,811,339	202,626	10973949	-162610	10811339
1986	10,218,418	207,842	11221765	-1003347	10218418
1987	11,371,926	213,657	11498039	-126113	11371926
1988	11,734,170	219,556	11778305	-44135	11734170
1989	11,671,254	230,551	12300685	-629431	11671254
1990	12,295,652	255,326	13477759	-1182107	12295652
1991	10,389,441	241,232	12808147	-2418706	10389441
1992	10,942,173	245,550	13013298	-2071126	10942173
1993	10,295,497	248,710	13163432	-2867935	10295497
1994	10,565,022	252,841	13359691	-2794670	10565022
1995	13,065,442	257,364	13574590	-509148	13065442
1996	14,459,684	261,170	13755416	704268	14459684
1997	12,701,288	265,545	13963275	-1261987	12701288
1998	16,724,906	265,545	13963275	2761631	16724906
1999	16,871,501	272,086	14274033	2597468	16871501
2000	15,489,381	273,808	14355856	1133525	15489381
2001	14,781,812	276,749	14495585	286227	14781812
2002	15,002,638	279,495	14626049	376589	15002638
2003	15,196,032	281,227	14708338	487694	15196032
2004	16,885,641	283,032	14794095	2091547	16885641

REGRESSION MODEL NO. 3 Distribution Plant Customer-Related Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.29
DURBIN WATSON STATISTIC = 1.79

After Cochrane Orcott Adjustment

X-VARIABLE COEFF.	t STATISTIC
-55615	-0.037
$ 53.99786	3.226

Line Estimate Results

53.99786	(55,615)	#N/A	#N/A
16.738079	1,483,161	#N/A	#N/A
0.285859	1,183,195	#N/A	#N/A
10.4074	26	#N/A	#N/A
###########	#############	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

	TRANSFORMED VARIABLES										ORIGINAL		RHO	0.63609		
	Y	X1	X2	X3	ESTIMATED		ADJUSTED FORECAST	ORIGINAL FORECAST		ADJUSTED FORECAST	ESTIMATED + RESIDUAL			LAGGED		
YEAR	EXPENSE	CUST'S	N/A	N/A	(Y)'t	RESIDUAL	(Y)	(Y)'	DIFFERENCE	(Y)	(Y)	DIFFERENCE	ERROR	ERROR	ERROR^2	E(t)*E(t-1)
1976													702,276			
1977	4,022,588	66,786	-	-	3,550,665	471,923	10,438,398	10,104,265	334,133	##########	##########	(471,923.5)	806,057	702,276	649,727,179,555	566,073,897,413
1978	4,477,970	67,988	-	-	3,615,588	862,382	10,555,494	10,147,547	407,946	##########	##########	(862,382.3)	1,270,329	806,057	1,613,734,885,729	1,023,956,745,109
1979	4,964,947	71,267	-	-	3,792,675	1,172,272	11,055,430	10,330,891	724,538	##########	##########	(1,172,271.7)	1,896,810	1,270,329	3,597,887,873,523	2,409,571,990,302
1980	4,455,491	72,342	-	-	3,850,688	604,804	11,628,560	10,498,557	1,130,004	##########	##########	(604,803.9)	1,734,808	1,896,810	3,009,557,833,913	3,290,600,497,676
1981	3,546,697	72,021	-	-	3,833,368	(286,671)	11,614,843	10,589,967	1,024,876	##########	##########	286,670.7	738,205	1,734,808	544,946,666,265	1,280,643,786,743
1982	2,479,977	71,529	-	-	3,806,810	(1,326,833)	11,012,505	10,624,745	387,760	##########	9,685,671.8	1,326,833.0	(939,073)	738,205	881,858,429,496	(693,228,541,876)
1983	3,186,524	73,624	-	-	3,919,902	(733,378)	10,080,825	10,746,372	(665,547)	##########	9,347,447.2	733,378.0	(1,398,925)	(939,073)	1,956,991,863,191	1,313,693,179,936
1984	4,500,845	69,435	-	-	3,693,739	807,106	9,639,522	10,624,745	(985,223)	9,639,522	10,446,628	(807,106)	(178,117)	(1,398,925)	31,725,729,074	249,172,618,181
1985	4,166,382	78,414	-	-	4,178,552	(12,170)	10,823,509	10,973,949	(150,440)	10,823,509	10,811,339	12,170	(162,610)	(178,117)	26,441,963,848	28,963,607,876
1986	3,341,473	78,954	-	-	4,207,752	(866,279)	11,084,697	11,221,765	(137,068)	11,084,697	10,218,418	866,279	(1,003,347)	(162,610)	1,006,705,165,267	163,154,103,796
1987	4,872,131	81,452	-	-	4,342,594	529,537	10,842,389	11,498,039	(655,650)	10,842,389	11,371,926	(529,537)	(126,113)	(1,003,347)	15,904,557,371	126,535,370,775
1988	4,500,644	83,652	-	-	4,461,398	39,246	11,694,924	11,778,305	(83,381)	11,694,924	11,734,170	(39,246)	(44,135)	(126,113)	1,947,912,720	5,566,029,969
1989	4,207,310	90,894	-	-	4,852,490	(645,180)	12,316,434	12,300,685	15,749	12,316,434	11,671,254	645,180	(629,431)	(44,135)	396,183,161,889	27,780,032,768
1990	4,871,727	108,676	-	-	5,812,634	(940,907)	13,236,559	13,477,759	(241,200)	13,236,559	12,295,652	940,907	(1,182,107)	(629,431)	1,397,377,892,063	744,054,831,065
1991	2,568,346	78,823	-	-	4,200,641	(1,632,295)	12,021,736	12,808,147	(786,411)	12,021,736	10,389,441	1,632,295	(2,418,706)	(1,182,107)	5,850,139,785,530	2,859,170,509,392
1992	4,333,592	92,106	-	-	4,917,892	(584,300)	11,526,473	13,013,298	(1,486,826)	11,526,473	10,942,173	584,300	(2,071,126)	(2,418,706)	4,289,561,615,148	5,009,444,586,704
1993	3,335,331	92,519	-	-	4,940,213	(1,604,882)	11,900,379	13,163,432	(1,263,053)	11,900,379	10,295,497	1,604,882	(2,867,935)	(2,071,126)	8,225,053,712,211	5,939,854,769,810
1994	4,016,198	94,640	-	-	5,054,733	(1,038,535)	11,603,557	13,359,691	(1,756,135)	11,603,557	10,565,022	1,038,535	(2,794,670)	(2,867,935)	7,810,178,288,133	8,014,932,059,715
1995	6,345,176	96,535	-	-	5,157,090	1,188,086	11,877,356	13,574,590	(1,697,234)	11,877,356	13,065,442	(1,188,086)	(509,148)	(2,794,670)	259,232,012,396	1,422,901,344,017
1996	6,148,936	97,464	-	-	5,207,248	941,688	13,517,996	13,755,416	(237,420)	13,517,996	14,459,684	(941,688)	704,268	(509,148)	495,993,607,716	(358,576,938,834)
1997	3,503,682	99,418	-	-	5,312,763	(1,809,081)	14,510,369	13,963,275	547,094	14,510,369	12,701,288	1,809,081	(1,261,987)	704,268	1,592,611,408,833	(888,777,294,015)
1998	8,645,791	96,635	-	-	5,162,493	3,483,298	13,241,608	13,963,275	(721,667)	13,241,608	16,724,906	(3,483,298)	2,761,631	(1,261,987)	7,626,605,377,203	(3,485,142,570,168)
1999	6,233,018	103,176	-	-	5,515,682	717,336	16,154,165	14,274,033	1,880,132	16,154,165	16,871,501	(717,336)	2,597,468	2,761,631	6,746,840,238,105	7,173,248,081,522
2000	4,757,650	100,738	-	-	5,384,019	(626,368)	16,115,749	14,355,856	1,759,893	16,115,749	15,489,381	626,368	1,133,525	2,597,468	1,284,878,186,934	2,944,294,117,894
2001	4,929,229	102,583	-	-	5,483,674	(554,444)	15,336,256	14,495,585	840,671	15,336,256	14,781,812	554,444	286,227	1,133,525	81,925,710,966	324,445,001,456
2002	5,600,131	103,459	-	-	5,530,936	69,194	14,933,444	14,626,049	307,394	14,933,444	15,002,638	(69,194)	376,589	286,227	141,819,113,294	107,789,756,866
2003	5,653,060	103,444	-	-	5,530,143	122,917	15,073,115	14,708,338	364,777	15,073,115	15,196,032	(122,917)	487,694	376,589	237,845,473,445	183,660,104,936
2004	7,219,654	104,147	-	-	5,568,120	1,651,535	15,234,107	14,794,095	440,012	15,234,107	16,885,641	(1,651,535)	2,091,547	487,694	4,374,567,416,579	1,020,034,831,912
												SUM	(702,276)	(2,091,547)	64,148,243,060,398	40,803,816,510,939

ORIGINAL REGRESSION D-W

SLOPE	0.677939266
INTERCEPT	25559.4983
DURBIN-WATSON	0.66
R-SQUARED	0.551

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
702,276				##########	
806,057	702,276	103,781	##########	##########	##########
1,270,329	806,057	464,272	##########	##########	##########
1,896,810	1,270,329	626,481	##########	##########	##########
1,734,808	1,896,810	(162,002)	##########	##########	##########
738,205	1,734,808	(996,603)	##########	##########	##########
(939,073)	738,205	(1,677,278)	##########	##########	##########
(1,398,925)	(939,073)	(459,852)	##########	##########	##########
(178,117)	(1,398,925)	1,220,808	##########	##########	##########
(162,610)	(178,117)	15,507	240,477,169	##########	##########
(1,003,347)	(162,610)	(840,737)	##########	##########	##########
(126,113)	(1,003,347)	877,234	##########	##########	##########
(44,135)	(126,113)	81,978	##########	##########	##########
(629,431)	(44,135)	(585,296)	##########	##########	##########
(1,182,107)	(629,431)	(552,677)	##########	##########	##########
(2,418,706)	(1,182,107)	(1,236,599)	##########	##########	##########
(2,071,126)	(2,418,706)	347,581	##########	##########	##########
(2,867,935)	(2,071,126)	(796,810)	##########	##########	##########
(2,794,670)	(2,867,935)	73,266	##########	##########	##########
(509,148)	(2,794,670)	2,285,521	##########	##########	##########
704,268	(509,148)	1,213,416	##########	##########	##########
(1,261,987)	704,268	(1,966,255)	##########	##########	##########
2,761,631	(1,261,987)	4,023,618	##########	##########	##########
2,597,468	2,761,631	(164,163)	##########	##########	##########
1,133,525	2,597,468	(1,463,943)	##########	##########	##########
286,227	1,133,525	(847,298)	##########	##########	##########
376,589	286,227	90,362	##########	##########	##########
487,694	376,589	111,105	##########	##########	##########
2,091,547	487,694	1,603,853	##########	##########	##########
(702,276)	(2,091,547)	1,389,271	##########	##########	##########

TRANSFORMED REGRESSION D-W

SLOPE	0.070727678
INTERCEPT	-13152.38069
DURBIN-WATSON	1.79
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
471,923				##########	
862,382	471,923	390,459	##########	##########	##########
1,172,272	862,382	309,889	##########	##########	##########
604,804	1,172,272	(567,468)	##########	##########	##########
(286,671)	604,804	(891,475)	##########	##########	##########
(1,326,833)	(286,671)	(1,040,162)	##########	##########	##########
(733,378)	(1,326,833)	593,455	##########	##########	##########
807,106	(733,378)	1,540,484	##########	##########	##########
(12,170)	807,106	(819,276)	##########	148,102,900	##########
(866,279)	(12,170)	(854,109)	##########	##########	##########
529,537	(866,279)	1,395,816	##########	##########	##########
39,246	529,537	(490,291)	##########	##########	##########
(645,180)	39,246	(684,425)	##########	##########	##########
(940,907)	(645,180)	(295,727)	##########	##########	##########
(1,632,295)	(940,907)	(691,389)	##########	##########	##########
(584,300)	(1,632,295)	1,047,996	##########	##########	##########
(1,604,882)	(584,300)	(1,020,583)	##########	##########	##########
(1,038,535)	(1,604,882)	566,348	##########	##########	##########
1,188,086	(1,038,535)	2,226,621	##########	##########	##########
941,688	1,188,086	(246,398)	##########	##########	##########
(1,809,081)	941,688	(2,750,769)	##########	##########	##########
3,483,298	(1,809,081)	5,292,379	##########	##########	##########
717,336	3,483,298	(2,765,962)	##########	##########	##########
(626,368)	717,336	(1,343,704)	##########	##########	##########
(554,444)	(626,368)	71,924	##########	##########	##########
69,194	(554,444)	623,639	##########	##########	##########
122,917	69,194	53,722	##########	##########	##########
1,651,535	122,917	1,528,618	##########	##########	##########
0	(1,651,535)	1,179,611	##########	##########	##########

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 4 Customer-Related Sales and Marketing E:

R SQUARED, ADJUSTED = 0.84
DURBIN WATSON STATISTIC = 0.51

		Before Cochrane Orcott Adjustment	
SMCUC =	Sales_ Mktg Customer Unit Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		2430	12.121
YEAR =	Year	$ (1.19)	-11.850
=			

Line Estimate Results

(1.19385)	2,430	#N/A	#N/A
0.100750	200	#N/A	#N/A
0.838723	5	#N/A	#N/A
140.4134	27	#N/A	#N/A
2.89E+03	5.56E+02	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR SMCUC YEAR

YEAR	SALES_ MKTG CUSTOMER UNIT COST	YEAR	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	62.82	1,976	71	-8	63
1977	64.22	1,977	70	-6	64
1978	63.97	1,978	69	-5	64
1979	64.72	1,979	68	-3	65
1980	64.19	1,980	66	-2	64
1981	70.29	1,981	65	5	70
1982	68.13	1,982	64	4	68
1983	64.70	1,983	63	2	65
1984	64.24	1,984	62	3	64
1985	62.65	1,985	60	2	63
1986	62.49	1,986	59	3	62
1987	61.60	1,987	58	4	62
1988	57.34	1,988	57	1	57
1989	52.14	1,989	56	-3	52
1990	50.24	1,990	54	-4	50
1991	56.64	1,991	53	3	57
1992	56.03	1,992	52	4	56
1993	52.71	1,993	51	2	53
1994	55.52	1,994	50	6	56
1995	54.58	1,995	48	6	55
1996	52.45	1,996	47	5	52
1997	44.96	1,997	46	-1	45
1998	48.04	1,998	45	3	48
1999	45.13	1,999	44	1	45
2000	44.11	2,000	42	2	44
2001	37.72	2,001	41	-4	38
2002	34.72	2,002	40	-5	35
2003	30.34	2,003	39	-9	30
2004	31.02	2,004	38	-7	31

REGRESSION MODEL NO. 4 Customer-Related Sales and Marketing Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.60
DURBIN WATSON STATISTIC = 2.05

After Cochrane Orcott Adjustment

	X-VARIABLE COEFF.	t STATISTIC
	853	6.334
$	(1.58878)	-6.234

Line Estimate Results

(1.58878)	853	#N/A	#N/A
0.254855	135	#N/A	#N/A
0.599158	3	#N/A	#N/A
38.8635	26	#N/A	#N/A
324	217	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

RHO 0.73478

YEAR	Y UNIT COST	TRANSFORMED VARIABLES X1 YEAR	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2
1976													(8)		
1977	18	525	-	-	19	(1)	65	70	(5)	65.4	64.2	1.1	(6)	(8)	33
1978	17	525	-	-	19	(2)	66	69	(3)	66.0	64.0	2.0	(5)	(6)	23
1979	18	526	-	-	18	(1)	65	68	(2)	65.4	64.7	0.6	(3)	(5)	8
1980	17	526	-	-	18	(1)	65	66	(1)	65.5	64.2	1.3	(2)	(3)	5
1981	23	526	-	-	18	6	65	65	(0)	64.7	70.3	(5.6)	5	(2)	26
1982	16	526	-	-	17	(1)	69	64	5	68.7	68.1	0.6	4	5	17
1983	15	527	-	-	17	(2)	67	63	4	66.7	64.7	2.0	2	4	4
1984	17	527	-	-	16	0	64	62	2	64	64	(0)	3	2	7
1985	15	527	-	-	16	(0)	63	60	3	63	63	0	2	3	5
1986	16	527	-	-	15	1	61	59	2	61	62	(1)	3	2	11
1987	16	528	-	-	15	1	61	58	3	61	62	(1)	4	3	13
1988	12	528	-	-	15	(2)	60	57	3	60	57	2	1	4	0
1989	10	528	-	-	14	(4)	56	56	1	56	52	4	(3)	1	12
1990	12	529	-	-	14	(2)	52	54	(2)	52	50	2	(4)	(3)	17
1991	20	529	-	-	13	6	50	53	(3)	50	57	(6)	3	(4)	12
1992	14	529	-	-	13	2	55	52	2	55	56	(2)	4	3	16
1993	12	529	-	-	12	(1)	54	51	3	54	53	1	2	4	4
1994	17	530	-	-	12	5	51	50	1	51	56	(5)	6	2	35
1995	14	530	-	-	12	2	52	48	4	52	55	(2)	6	6	38
1996	12	530	-	-	11	1	51	47	4	51	52	(1)	5	6	27
1997	6	530	-	-	11	(4)	49	46	3	49	45	4	(1)	5	1
1998	15	531	-	-	10	5	43	45	(1)	43	48	(5)	3	(1)	10
1999	10	531	-	-	10	(0)	45	44	2	45	45	0	1	3	2
2000	11	531	-	-	10	1	43	42	0	43	44	(1)	2	1	3
2001	5	531	-	-	9	(4)	41	41	0	41	38	4	(4)	2	13
2002	7	532	-	-	9	(2)	36	40	(4)	36	35	2	(5)	(4)	29
2003	5	532	-	-	8	(3)	34	39	(5)	34	30	3	(9)	(5)	73
2004	9	532	-	-	8	1	30	38	(8)	30	31	(1)	(7)	(9)	44
												SUM	8	7	487

E(t)*E(t-1)
47
27
13
6
(11)
21
8
5
6
8
12
2
(2)
14
(14)
14
8
11
36
32
(6)
(3)
5
2
(6)
19
46
57
358

ORIGINAL REGRESSION D-W

SLOPE	0.697984143
INTERCEPT	0.130254087
DURBIN-WATSON	0.51
R-SQUARED	0.839

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(8)				69	
(6)	(8)	3	7	33	47
(5)	(6)	1	1	23	27
(3)	(5)	2	4	8	13
(2)	(3)	1	0	5	6
5	(2)	7	53	26	(11)
4	5	(1)	1	17	21
2	4	(2)	5	4	8
3	2	1	1	7	5
2	3	(0)	0	5	6
3	2	1	1	11	8
4	3	0	0	13	12
1	4	(3)	9	0	2
(3)	1	(4)	16	12	(2)
(4)	(3)	(1)	0	17	14
3	(4)	8	58	12	(14)
4	3	1	0	16	14
2	4	(2)	5	4	8
6	2	4	16	35	11
6	6	0	0	38	36
5	6	(1)	1	27	32
(1)	5	(6)	40	1	(6)
3	(1)	4	18	10	(3)
1	3	(2)	3	2	5
2	1	0	0	3	2
(4)	2	(5)	27	13	(6)
(5)	(4)	(2)	3	29	19
(9)	(5)	(3)	10	73	46
(7)	(9)	2	4	44	57
8	7	2	283	556	358

TRANSFORMED REGRESSION D-W

SLOPE	-0.031561282
INTERCEPT	0.041264375
DURBIN-WATSON	2.05
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(1)				1	
(2)	(1)	(1)	1	4	2
(1)	(2)	1	2	0	1
(1)	(1)	(1)	0	2	1
6	(1)	7	48	31	(7)
(1)	6	(6)	39	0	(3)
(2)	(1)	(1)	2	4	1
0	(2)	2	6	0	(1)
(0)	0	(1)	1	0	(0)
1	(0)	1	2	1	(0)
1	1	(0)	0	0	1
(2)	1	(3)	10	6	(2)
(4)	(2)	(2)	3	17	10
(2)	(4)	2	6	3	7
6	(2)	8	67	41	(12)
2	6	(5)	24	2	10
(1)	2	(2)	6	1	(1)
5	(1)	6	32	23	(4)
2	5	(3)	7	5	10
1	2	(1)	1	1	2
(4)	1	(6)	30	19	(5)
5	(4)	9	81	22	(20)
(0)	5	(5)	22	0	(0)
1	(0)	2	2	2	(0)
(4)	1	(5)	27	14	(5)
(2)	(4)	2	4	3	6
(3)	(2)	(2)	3	12	6
1	(3)	4	19	1	(3)
0	(1)	2	446	217	(7)

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 5 Production Capacity-Related Expenses

R SQUARED, ADJUSTED = 0.66
DURBIN WATSON STATISTIC = 1.12

		Before Cochrane Orcott Adjustment	
PCEUC =	Prod Cap Expense Unit Cost	X-VARIABLE COEFF.	t STATISTIC
CONSTANT		343	7.359
YEAR =	Year	$ (0.17096)	-7.304
=			

Line Estimate Results

(0.17096)	343	#N/A	#N/A
0.023405	47	#N/A	#N/A
0.663985	1	#N/A	#N/A
53.3535	27	#N/A	#N/A
5.93E+01	3.00E+01	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR PCEUC YEAR

YEAR	PROD CAP EXPENSE UNIT COST	YEAR	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	$7.13	1,976	5	2	7
1977	$8.42	1,977	5	4	8
1978	$3.74	1,978	5	-1	4
1979	$3.85	1,979	4	-1	4
1980	$3.64	1,980	4	-1	4
1981	$3.41	1,981	4	-1	3
1982	$2.64	1,982	4	-1	3
1983	$1.44	1,983	4	-2	1
1984	$3.40	1,984	4	0	3
1985	$3.19	1,985	3	0	3
1986	$2.86	1,986	3	0	3
1987	$3.70	1,987	3	1	4
1988	$2.67	1,988	3	0	3
1989	$1.77	1,989	3	-1	2
1990	$2.30	1,990	3	0	2
1991	$2.75	1,991	2	0	3
1992	$2.08	1,992	2	0	2
1993	$1.64	1,993	2	0	2
1994	$1.96	1,994	2	0	2
1995	$1.59	1,995	2	0	2
1996	$2.12	1,996	2	1	2
1997	$1.22	1,997	1	0	1
1998	$1.10	1,998	1	0	1
1999	$0.89	1,999	1	0	1
2000	$0.88	2,000	1	0	1
2001	$0.83	2,001	1	0	1
2002	$0.77	2,002	0	0	1
2003	$0.80	2,003	0	0	1
2004	$0.75	2,004	0	1	1

REGRESSION MODEL NO. 5 Production Capacity-Related Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =	0.36
DURBIN WATSON STATISTIC =	2.27

After Cochrane Orcott Adjustment

X-VARIABLE COEFF.	t STATISTIC
159	3.819
$ (0.13712)	-3.789

Line Estimate Results

(0.13712)	159	#N/A	#N/A
0.036189	41	#N/A	#N/A
0.355728	1	#N/A	#N/A
14.3556	26	#N/A	#N/A
11	21	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

	TRANSFORMED VARIABLES										ORIGINAL		RHO	0.42411		
	Y	X1	X2	X3	ESTIMATED		ADJUSTED FORECAST	ORIGINAL FORECAST		ADJUSTED FORECAST	ESTIMATED + RESIDUAL			LAGGED		
YEAR	UNIT COST	YEAR	N/A	N/A	(Y)'t	RESIDUAL	(Y)	(Y)'	DIFFERENCE	(Y)	(Y)	DIFFERENCE	ERROR	ERROR	ERROR^2	E(t)*E(t-1)
1976													2			
1977	5	1,139	-	-	2	3	5	5	1	5.4	8.4	(3.1)	4	2	13	8
1978	0	1,140	-	-	2	(2)	6	5	1	5.8	3.7	2.1	(1)	4	1	(3)
1979	2	1,140	-	-	2	0	4	4	(1)	3.8	3.8	(0.1)	(1)	(1)	0	0
1980	2	1,141	-	-	2	(0)	4	4	(1)	3.7	3.6	0.1	(1)	(1)	0	0
1981	2	1,141	-	-	2	(0)	4	4	(1)	3.6	3.4	0.1	(1)	(1)	0	0
1982	1	1,142	-	-	2	(1)	3	4	(1)	3.4	2.6	0.8	(1)	(1)	2	1
1983	0	1,142	-	-	2	(2)	3	4	(1)	3.0	1.4	1.5	(2)	(1)	5	3
1984	3	1,143	-	-	2	1	2	4	(1)	2	3	(1)	(0)	(2)	0	0
1985	2	1,144	-	-	2	0	3	3	(0)	3	3	(0)	(0)	(0)	0	0
1986	2	1,144	-	-	2	(0)	3	3	(0)	3	3	0	(0)	(0)	0	0
1987	2	1,145	-	-	2	1	3	3	(0)	3	4	(1)	1	(0)	0	(0)
1988	1	1,145	-	-	1	(0)	3	3	0	3	3	0	(0)	1	0	(0)
1989	1	1,146	-	-	1	(1)	3	3	(0)	3	2	1	(1)	(0)	1	0
1990	2	1,146	-	-	1	0	2	3	(0)	2	2	(0)	(0)	(1)	0	0
1991	2	1,147	-	-	1	1	2	2	(0)	2	3	(1)	0	(0)	0	(0)
1992	1	1,148	-	-	1	(0)	2	2	0	2	2	0	(0)	0	0	(0)
1993	1	1,148	-	-	1	(0)	2	2	(0)	2	2	0	(0)	(0)	0	0
1994	1	1,149	-	-	1	0	2	2	(0)	2	2	(0)	0	(0)	0	(0)
1995	1	1,149	-	-	1	(0)	2	2	0	2	2	0	(0)	0	0	(0)
1996	1	1,150	-	-	1	1	2	2	(0)	2	2	(1)	1	(0)	0	(0)
1997	0	1,150	-	-	1	(0)	2	1	0	2	1	0	(0)	1	0	(0)
1998	1	1,151	-	-	1	(0)	1	1	0	1	1	0	(0)	(0)	0	0
1999	0	1,152	-	-	1	(0)	1	1	0	1	1	0	(0)	(0)	0	0
2000	0	1,152	-	-	1	(0)	1	1	0	1	1	0	0	(0)	0	(0)
2001	0	1,153	-	-	0	0	1	1	0	1	1	(0)	0	0	0	0
2002	0	1,153	-	-	0	0	1	0	0	1	1	(0)	0	0	0	0
2003	0	1,154	-	-	0	0	1	0	0	1	1	(0)	0	0	0	0
2004	0	1,155	-	-	0	0	1	0	0	1	1	(0)	1	0	0	0
												SUM	(2)	(1)	25	11

ORIGINAL REGRESSION D-W

SLOPE	0.358703273
INTERCEPT	-0.070816096
DURBIN-WATSON	1.12
R-SQUARED	0.664

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
2				5	
4	2	1	2	13	8
(1)	4	(5)	20	1	(3)
(1)	(1)	0	0	0	0
(1)	(1)	(0)	0	0	0
(1)	(1)	(0)	0	0	0
(1)	(1)	(1)	0	2	1
(2)	(1)	(1)	1	5	3
(0)	(2)	2	5	0	0
(0)	(0)	(0)	0	0	0
(0)	(0)	(0)	0	0	0
1	(0)	1	1	0	(0)
(0)	1	(1)	1	0	(0)
(1)	(0)	(1)	1	1	0
(0)	(1)	1	0	0	0
0	(0)	1	0	0	(0)
(0)	0	(0)	0	0	(0)
(0)	(0)	(0)	0	0	0
0	(0)	0	0	0	(0)
(0)	0	(0)	0	0	(0)
1	(0)	1	0	0	(0)
(0)	1	(1)	1	0	(0)
(0)	(0)	0	0	0	0
(0)	(0)	(0)	0	0	0
0	(0)	0	0	0	(0)
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
1	0	0	0	0	0
(2)	(1)	(2)	33	30	11

TRANSFORMED REGRESSION D-W

SLOPE	-0.364217274
INTERCEPT	-0.11624819
DURBIN-WATSON	2.27
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
3				9	
(2)	3	(5)	27	4	(6)
0	(2)	2	5	0	(0)
(0)	0	(0)	0	0	(0)
(0)	(0)	(0)	0	0	0
(1)	(0)	(1)	0	1	0
(2)	(1)	(1)	1	2	1
1	(2)	3	6	1	(2)
0	1	(1)	1	0	0
(0)	0	(0)	0	0	(0)
1	(0)	1	1	1	(0)
(0)	1	(1)	2	0	(0)
(1)	(0)	(0)	0	1	0
0	(1)	1	1	0	(0)
1	0	0	0	0	0
(0)	1	(1)	1	0	(0)
(0)	(0)	(0)	0	0	0
0	(0)	1	0	0	(0)
(0)	0	(0)	0	0	(0)
1	(0)	1	1	0	(0)
(0)	1	(1)	1	0	(0)
(0)	(0)	0	0	0	0
(0)	(0)	(0)	0	0	0
(0)	(0)	0	0	0	0
0	(0)	0	0	0	(0)
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
(0)	(0)	(3)	47	21	(7)

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 6 Admin and General Expenses

R SQUARED, ADJUSTED = 0.94
DURBIN WATSON STATISTIC = 0.01

		Before Cochrane Orcott Adjustment		
A_G_EXP =	Admin General Expense	X-VARIABLE COEFF.	t STATISTIC	
CONSTANT		0	1.808	
SENDOUT =	Total Sendout	$ 98.69692	4.597	
DDD =	Design Day Demand	$ 0.33	1.8084	#

Line Estimate Results

98.69692	0	(25,891,182)	#N/A
21.469977	0	3,323,056	#N/A
0.935047	3,709,992	#N/A	#N/A
187.1435	26	#N/A	#N/A
5.15E+15	3.58E+14	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	A_G_EXP	SENDOUT	DDD			
YEAR	ADMIN GENERAL EXPENSE	TOTAL SENDOUT	DESIGN DAY DEMAND	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	7,704,755	32,084,486	226,225	3166714334	-3159009579	7704755
1977	9,157,990	32,501,202	221,937	3207841505	-3198683515	9157990
1978	8,713,993	33,617,370	231,994	3318007157	-3309293164	8713993
1979	10,536,659	35,231,902	255,527	3477364238	-3466827579	10536659
1980	12,479,646	38,848,855	251,000	3834344853	-3821865207	12479646
1981	12,907,604	38,783,112	265,000	3827860833	-3814953229	12907604
1982	14,682,639	41,226,356	283,000	4069007410	-4054324771	14682639
1983	14,238,341	40,742,561	261,000	4021251089	-4007012748	14238341
1984	14,366,468	45,641,095	266,366	4504723055	-4490356586	14366468
1985	16,309,308	45,991,117	271,605	4539270872	-4522961564	16309308
1986	19,433,609	41,447,436	292,425	4090830428	-4071396819	19433609
1987	21,137,450	51,464,008	307,637	5079440204	-5058302753	21137450
1988	22,006,791	50,547,388	317,241	4988975800	-4966969009	22006791
1989	24,896,734	54,384,674	340,491	5367711752	-5342815018	24896734
1990	24,327,632	49,991,807	366,674	4934157951	-4909830319	24327632
1991	27,845,712	52,150,644	377,978	5147232229	-5119386517	27845712
1992	28,227,858	53,004,733	387,149	5231531200	-5203303341	28227858
1993	34,806,316	52,536,119	405,800	5185286587	-5150480271	34806316
1994	28,583,151	56,275,458	421,578	5554352989	-5525769838	28583151
1995	29,152,058	57,743,912	436,181	5699289750	-5670137692	29152058
1996	30,397,402	60,185,452	453,181	5940267741	-5909870340	30397402
1997	45,086,281	66,000,496	469,409	6514199980	-6469113699	45086281
1998	47,644,386	64,486,186	477,243	6364744852	-6317100466	47644386
1999	37,395,189	62,877,591	434,840	6205967552	-6168572363	37395189
2000	36,195,130	69,292,942	445,550	6839146412	-6802951282	36195130
2001	41,107,619	62,271,329	455,990	6146138360	-6105030741	41107619
2002	52,474,713	67,536,993	465,290	6665846151	-6613371438	52474713
2003	51,427,610	69,654,803	545,890	6874894047	-6823466437	51427610
2004	51,843,205	64,156,651	551,630	6332245284	-6280402079	51843205

REGRESSION MODEL NO. 6 Admin and General Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =	0.09
DURBIN WATSON STATISTIC =	2.15

After Cochrane Orcott Adjustment

	X-VARIABLE COEFF.	t STATISTIC
	0	0.725
$	55.53754	1.267
	0.168501	0.725

Line Estimate Results

55.53754	0	684,036	#N/A
43.835132	0	1,264,608	#N/A
0.087477	4,462,028	#N/A	#N/A
1.1983	25	#N/A	#N/A
###########	############	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

RHO 0.97808

YEAR	TRANSFORMED VARIABLES Y EXPENSE	X1 SENDOUT	X2 DEMAND	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2
1976													##########		
1977	1,622,109	1,119,948	671	-	62,199,286	(60,577,177)	69,735,167	3,207,841,505	##########	69,735,166.6	9,157,990.1	60,577,176.6	##########	##########	#################
1978	(243,271)	1,828,534	14,922	-	101,554,787	(101,798,058)	110,512,051	3,318,007,157	##########	##########	8,713,993.3	##########	##########	##########	#################
1979	2,013,660	2,351,362	28,618	-	130,593,692	(128,580,033)	139,116,691	3,477,364,238	##########	##########	10,536,658.5	##########	##########	##########	#################
1980	2,173,931	4,389,171	1,074	-	243,763,916	(241,589,985)	254,069,631	3,834,344,853	##########	##########	12,479,645.8	##########	##########	##########	#################
1981	701,488	785,752	19,501	-	43,642,003	(42,940,515)	55,848,119	3,827,860,833	##########	55,848,118.6	12,907,603.6	42,940,515.0	##########	##########	#################
1982	2,057,946	3,293,298	23,808	-	182,905,657	(180,847,712)	195,530,350	4,069,007,410	##########	##########	14,682,638.6	##########	##########	##########	#################
1983	(122,482)	419,810	(15,797)	-	23,312,561	(23,435,043)	37,673,384	4,021,251,089	##########	37,673,383.7	14,238,340.9	23,435,042.8	##########	##########	#################
1984	440,205	5,791,535	11,087	-	321,649,468	(321,209,262)	335,575,731	4,504,723,055	##########	335,575,731	14,366,468	321,209,262	##########	##########	#################
1985	2,257,726	1,350,390	11,077	-	74,999,203	(72,741,477)	89,050,785	4,539,270,872	##########	89,050,785	16,309,308	72,741,477	##########	##########	#################
1986	3,481,770	(3,535,641)	26,773	-	(196,356,284)	199,838,054	(180,404,445)	4,090,830,428	##########	(180,404,445)	19,433,609	(199,838,054)	##########	##########	#################
1987	2,129,790	10,925,023	21,621	-	606,752,492	(604,622,702)	625,760,153	5,079,440,204	##########	625,760,153	21,137,450	604,622,702	##########	##########	#################
1988	1,332,635	211,376	16,347	-	11,742,029	(10,409,395)	32,416,186	4,988,975,800	##########	32,416,186	22,006,791	10,409,395	##########	##########	#################
1989	3,372,290	4,945,191	30,203	-	274,648,807	(271,276,516)	296,173,250	5,367,711,752	##########	296,173,250	24,896,734	271,276,516	##########	##########	#################
1990	(23,411)	(3,200,856)	33,646	-	(177,761,981)	177,738,570	(153,410,938)	4,934,157,951	##########	(153,410,938)	24,327,632	(177,738,570)	##########	##########	#################
1991	4,051,296	3,254,565	19,341	-	180,753,757	(176,702,461)	204,548,173	5,147,232,229	##########	204,548,173	27,845,712	176,702,461	##########	##########	#################
1992	992,473	1,997,134	17,456	-	110,918,859	(109,926,386)	138,154,245	5,231,531,200	##########	138,154,245	28,227,858	109,926,386	##########	##########	#################
1993	7,197,160	693,151	27,137	-	38,500,490	(31,303,330)	66,109,646	5,185,286,587	##########	66,109,646	34,806,316	31,303,330	##########	##########	#################
1994	(5,460,276)	4,890,833	24,672	-	271,628,969	(277,089,245)	305,672,395	5,554,352,989	##########	305,672,395	28,583,151	277,089,245	##########	##########	#################
1995	1,195,397	2,701,908	23,843	-	150,061,345	(148,865,948)	178,018,006	5,699,289,750	##########	178,018,006	29,152,058	148,865,948	##########	##########	#################
1996	1,884,303	3,707,179	26,560	-	205,892,039	(204,007,737)	234,405,138	5,940,267,741	##########	234,405,138	30,397,402	204,007,737	##########	##########	#################
1997	15,355,134	7,134,197	26,161	-	396,220,142	(380,865,008)	425,951,289	6,514,199,980	##########	425,951,289	45,086,281	380,865,008	##########	##########	#################
1998	3,546,313	(67,701)	18,123	-	(3,756,920)	7,303,233	40,341,153	6,364,744,852	##########	40,341,153	47,644,386	(7,303,233)	##########	##########	#################
1999	(9,204,921)	(195,177)	(31,943)	-	(10,845,044)	1,640,123	35,755,066	6,205,967,552	##########	35,755,066	37,395,189	(1,640,123)	##########	##########	#################
2000	(380,425)	7,793,511	20,241	-	432,835,797	(433,216,222)	469,411,353	6,839,146,412	##########	469,411,353	36,195,130	433,216,222	##########	##########	#################
2001	5,705,819	(5,502,840)	20,206	-	(305,610,758)	311,316,577	(270,208,958)	6,146,138,360	##########	(270,208,958)	41,107,619	(311,316,577)	##########	##########	#################
2002	12,268,096	6,630,535	19,294	-	368,246,839	(355,978,743)	408,453,456	6,665,846,151	##########	408,453,456	52,474,713	355,978,743	##########	##########	#################
2003	103,045	3,598,096	90,798	-	199,844,675	(199,741,630)	251,169,240	6,874,894,047	##########	251,169,240	51,427,610	199,741,630	##########	##########	#################
2004	1,542,793	(3,971,448)	17,705	-	(220,561,459)	222,104,252	(170,261,047)	6,332,245,284	##########	(170,261,047)	51,843,205	(222,104,252)	##########	##########	#################
												SUM	##########	##########	#################

E(t)*E(t-1)
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ORIGINAL REGRESSION D-W

SLOPE	0.916992704
INTERCEPT	-526731659.4
DURBIN-WATSON	0.01
R-SQUARED	0.935

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
##########				##########	
##########	##########	(39,673,937)	##########	##########	##########
##########	##########	(110,609,649)	##########	##########	##########
##########	##########	(157,534,415)	##########	##########	##########
##########	##########	(355,037,628)	##########	##########	##########
##########	##########	6,911,978	##########	##########	##########
##########	##########	(239,371,542)	##########	##########	##########
##########	##########	47,312,023	##########	##########	##########
##########	##########	(483,343,839)	##########	##########	##########
##########	##########	(32,604,978)	##########	##########	##########
##########	##########	451,564,745	##########	##########	##########
##########	##########	(986,905,934)	##########	##########	##########
##########	##########	91,333,745	##########	##########	##########
##########	##########	(375,846,010)	##########	##########	##########
##########	##########	432,984,699	##########	##########	##########
##########	##########	(209,556,197)	##########	##########	##########
##########	##########	(83,916,825)	##########	##########	##########
##########	##########	52,823,071	##########	##########	##########
##########	##########	(375,289,568)	##########	##########	##########
##########	##########	(144,367,853)	##########	##########	##########
##########	##########	(239,732,648)	##########	##########	##########
##########	##########	(559,243,360)	##########	##########	##########
##########	##########	152,013,234	##########	##########	##########
##########	##########	148,528,103	##########	##########	##########
##########	##########	(634,378,919)	##########	##########	##########
##########	##########	697,920,541	##########	##########	##########
##########	##########	(508,340,697)	##########	##########	##########
##########	##########	(210,094,999)	##########	##########	##########
##########	##########	543,064,358	##########	##########	##########
##########	##########	##########	##########	##########	##########

TRANSFORMED REGRESSION D-W

SLOPE	-0.593263401
INTERCEPT	-206679610.4
DURBIN-WATSON	2.15
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(60,577,177)				##########	
(101,798,058)	(60,577,177)	(41,220,882)	##########	##########	##########
(128,580,033)	(101,798,058)	(26,781,975)	##########	##########	##########
(241,589,985)	(128,580,033)	(113,009,952)	##########	##########	##########
(42,940,515)	(241,589,985)	198,649,470	##########	##########	##########
(180,847,712)	(42,940,515)	(137,907,197)	##########	##########	##########
(23,435,043)	(180,847,712)	157,412,669	##########	##########	##########
(321,209,262)	(23,435,043)	(297,774,220)	##########	##########	##########
(72,741,477)	(321,209,262)	248,467,785	##########	##########	##########
199,838,054	(72,741,477)	272,579,531	##########	##########	##########
(604,622,702)	199,838,054	(804,460,756)	##########	##########	##########
(10,409,395)	(604,622,702)	594,213,307	##########	##########	##########
(271,276,516)	(10,409,395)	(260,867,121)	##########	##########	##########
177,738,570	(271,276,516)	449,015,086	##########	##########	##########
(176,702,461)	177,738,570	(354,441,030)	##########	##########	##########
(109,926,386)	(176,702,461)	66,776,074	##########	##########	##########
(31,303,330)	(109,926,386)	78,623,056	##########	##########	##########
(277,089,245)	(31,303,330)	(245,785,915)	##########	##########	##########
(148,865,948)	(277,089,245)	128,223,297	##########	##########	##########
(204,007,737)	(148,865,948)	(55,141,789)	##########	##########	##########
(380,865,008)	(204,007,737)	(176,857,272)	##########	##########	##########
7,303,233	(380,865,008)	388,168,241	##########	##########	##########
1,640,123	7,303,233	(5,663,111)	##########	##########	##########
(433,216,222)	1,640,123	(434,856,345)	##########	##########	##########
311,316,577	(433,216,222)	744,532,799	##########	##########	##########
(355,978,743)	311,316,577	(667,295,320)	##########	##########	##########
(199,741,630)	(355,978,743)	156,237,113	##########	##########	##########
222,104,252	(199,741,630)	421,845,882	##########	##########	##########
##########	##########	282,681,429	##########	##########	##########

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 7 Admin and General Expenses

R SQUARED, ADJUSTED = 0.92
DURBIN WATSON STATISTIC = 0.01

		Before Cochrane Orcott Adjustment		
A_G_EXP =	Admin General Expense	X-VARIABLE COEFF.	t STATISTIC	
CONSTANT		266	3.388	
CUST =	Cust'S	$ 0.36312	1.556	
TOT SO =	Total Firm Sendout	$ 266.37	3.3884	#

Line Estimate Results

0.36312	266	(53,603,117)	#N/A
0.233317	79	7,577,219	#N/A
0.918323	4,160,287	#N/A	#N/A
146.1626	26	#N/A	#N/A
5.06E+15	4.50E+14	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	A_G_EXP	CUST	TOT SO			
YEAR	ADMIN GENERAL EXPENSE	CUST'S	TOTAL FIRM SENDOUT	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	7,704,755	184,779	32,084,486	8546347251	-8538642496	7704755
1977	9,157,990	184,321	32,501,202	8657346886	-8648188896	9157990
1978	8,713,993	185,232	33,617,370	8954658638	-8945944644	8713993
1979	10,536,659	189,091	35,231,902	9384719675	-9374183016	10536659
1980	12,479,646	192,620	38,848,855	10348161439	-10335681793	12479646
1981	12,907,604	194,544	38,783,112	10330650307	-10317742703	12907604
1982	14,682,639	195,276	41,226,356	10981452554	-10966769915	14682639
1983	14,238,341	197,836	40,742,561	10852585984	-10838347643	14238341
1984	14,366,468	195,276	45,641,095	12157397686	-12143031218	14366468
1985	16,309,308	202,626	45,991,117	12250635010	-12234325702	16309308
1986	19,433,609	207,842	41,447,436	11040345751	-11020912142	19433609
1987	21,137,450	213,657	51,464,008	13708441963	-13687304513	21137450
1988	22,006,791	219,556	50,547,388	13464285883	-13442279092	22006791
1989	24,896,734	226,230	54,384,674	14486418446	-14461521713	24896734
1990	24,327,632	230,551	49,991,807	13316300884	-13291973252	24327632
1991	27,845,712	255,326	52,150,644	13891354942	-13863509230	27845712
1992	28,227,858	241,232	53,004,733	14118851790	-14090623932	28227858
1993	34,806,316	245,550	52,536,119	13994029591	-13959223275	34806316
1994	28,583,151	248,710	56,275,458	14990070875	-14961487725	28583151
1995	29,152,058	252,841	57,743,912	15381221697	-15352069639	29152058
1996	30,397,402	257,364	60,185,452	16031571224	-16001173822	30397402
1997	45,086,281	261,170	66,000,496	17580514118	-17535427837	45086281
1998	47,644,386	265,545	64,486,186	17177152053	-17129507666	47644386
1999	37,395,189	272,086	62,877,591	16748676305	-16711281116	37395189
2000	36,195,130	273,808	69,292,942	18457520981	-18421325851	36195130
2001	41,107,619	276,749	62,271,329	16587189296	-16546081677	41107619
2002	52,474,713	279,495	67,536,993	17989794415	-17937319703	52474713
2003	51,427,610	281,227	69,654,803	18553911913	-18502484303	51427610
2004	51,843,205	283,032	64,156,651	17089380878	-17037537672	51843205

REGRESSION MODEL NO. 7 Admin and General Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =	0.04
DURBIN WATSON STATISTIC =	2.14

After Cochrane Orcott Adjustment

	X-VARIABLE COEFF.	t STATISTIC
	83	0.544
$	0.20414	0.863
	82.968475	0.544

Line Estimate Results

0.20414	83	971,593	#N/A
0.236519	152	1,652,292	#N/A
0.040260	4,575,989	#N/A	#N/A
0.5244	25	#N/A	#N/A
###########	##############	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

RHO 0.97798

YEAR	Y EXPENSE	X1 CUST'S	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2
1976													###########		
1977	1,622,894	3,611	1,123,217	-	93,192,393	(91,569,499)	100,727,489	8,657,346,886	###########	###########	9,157,990.1	91,569,498.8	###########	###########	##################
1978	(242,338)	4,970	1,831,845	-	151,986,462	(152,228,800)	160,942,793	8,954,658,638	###########	###########	8,713,993.3	###########	###########	###########	##################
1979	2,014,547	7,938	2,354,787	-	195,374,770	(193,360,223)	203,896,881	9,384,719,675	###########	###########	10,536,658.5	###########	###########	###########	##################
1980	2,175,005	7,693	4,392,760	-	364,462,232	(362,287,227)	374,766,873	10,348,161,439	###########	###########	12,479,645.8	###########	###########	###########	##################
1981	702,760	6,165	789,709	-	65,522,303	(64,819,543)	77,727,147	10,330,650,307	###########	77,727,146.6	12,907,603.6	64,819,543.0	###########	###########	##################
1982	2,059,261	5,016	3,297,248	-	273,568,782	(271,509,521)	286,192,160	10,981,452,554	###########	###########	14,682,638.6	###########	###########	###########	##################
1983	(120,986)	6,860	424,010	-	35,180,923	(35,301,908)	49,540,249	10,852,585,984	###########	49,540,249.3	14,238,340.9	35,301,908.4	###########	###########	##################
1984	441,656	1,796	5,795,686	-	480,859,638	(480,417,982)	494,784,451	12,157,397,686	###########	494,784,451	14,366,468	480,417,982	###########	###########	##################
1985	2,259,190	11,650	1,355,039	-	112,428,005	(110,168,815)	126,478,124	12,250,635,010	###########	126,478,124	16,309,308	110,168,815	###########	###########	##################
1986	3,483,432	9,678	(3,530,956)	-	(292,955,991)	296,439,423	(277,005,814)	11,040,345,751	###########	(277,005,814)	19,433,609	(296,439,423)	###########	###########	##################
1987	2,131,770	10,392	#########	-	906,784,981	(904,653,211)	925,790,662	13,708,441,963	###########	925,790,662	21,137,450	904,653,211	###########	###########	##################
1988	1,334,788	10,604	216,618	-	17,974,704	(16,639,917)	38,646,708	13,464,285,883	###########	38,646,708	22,006,791	16,639,917	###########	###########	##################
1989	3,374,532	11,509	4,950,340	-	410,724,584	(407,350,051)	432,246,785	14,486,418,446	###########	432,246,785	24,896,734	407,350,051	###########	###########	##################
1990	(20,875)	9,303	(3,195,316)	-	(265,108,513)	265,087,638	(240,760,005)	13,316,300,884	###########	(240,760,005)	24,327,632	(265,087,638)	###########	###########	##################
1991	4,053,774	29,852	3,259,657	-	270,454,947	(266,401,173)	294,246,885	13,891,354,942	###########	294,246,885	27,845,712	266,401,173	###########	###########	##################
1992	995,309	(8,472)	2,002,447	-	166,138,296	(165,142,987)	193,370,845	14,118,851,790	###########	193,370,845	28,227,858	165,142,987	###########	###########	##################
1993	7,200,035	9,630	698,551	-	57,959,733	(50,759,697)	85,566,013	13,994,029,591	###########	85,566,013	34,806,316	50,759,697	###########	###########	##################
1994	(5,456,730)	8,567	4,896,185	-	406,230,797	(411,687,527)	440,270,677	14,990,070,875	###########	440,270,677	28,583,151	411,687,527	###########	###########	##################
1995	1,198,309	9,607	2,707,641	-	224,650,869	(223,452,560)	252,604,618	15,381,221,697	###########	252,604,618	29,152,058	223,452,560	###########	###########	##################
1996	1,887,272	10,091	3,713,061	-	308,069,123	(306,181,851)	336,579,253	16,031,571,224	###########	336,579,253	30,397,402	306,181,851	###########	###########	##################
1997	15,358,230	9,473	7,140,328	-	592,424,139	(577,065,909)	622,152,190	17,580,514,118	###########	622,152,190	45,086,281	577,065,909	###########	###########	##################
1998	3,550,906	10,126	(60,978)	-	(5,057,129)	8,608,035	39,036,351	17,177,152,053	###########	39,036,351	47,644,386	(8,608,035)	###########	###########	##################
1999	(9,200,068)	12,388	(188,608)	-	(15,645,932)	6,445,864	30,949,325	16,748,676,305	###########	30,949,325	37,395,189	(6,445,864)	###########	###########	##################
2000	(376,616)	7,714	7,799,916	-	647,148,776	(647,525,392)	683,720,523	18,457,520,981	###########	683,720,523	36,195,130	647,525,392	###########	###########	##################
2001	5,709,506	8,970	(5,495,781)	-	(455,974,672)	461,684,178	(420,576,559)	16,587,189,296	###########	(420,576,559)	41,107,619	(461,684,178)	###########	###########	##################
2002	12,272,284	8,840	6,636,879	-	550,653,573	(538,381,289)	590,856,002	17,989,794,415	###########	590,856,002	52,474,713	538,381,289	###########	###########	##################
2003	108,391	7,886	3,604,975	-	299,101,009	(298,992,619)	350,420,229	18,553,911,913	###########	350,420,229	51,427,610	298,992,619	###########	###########	##################
2004	1,548,032	7,998	(3,964,353)	-	(328,914,582)	330,462,613	(278,619,408)	17,089,380,878	###########	(278,619,408)	51,843,205	(330,462,613)	###########	###########	##################
												SUM	###########	###########	##################

E(t)*E(t-1)
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ORIGINAL REGRESSION D-W

SLOPE		0.917918219
INTERCEPT		-1415324898
DURBIN-WATSON		0.01
R-SQUARED		0.918

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
###########				###########	
###########	###########	(109,546,400)	###########	###########	###########
###########	###########	(297,755,749)	###########	###########	###########
###########	###########	(428,238,372)	###########	###########	###########
###########	###########	(961,498,777)	###########	###########	###########
###########	###########	17,939,090	###########	###########	###########
###########	###########	(649,027,212)	###########	###########	###########
###########	###########	128,422,272	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	(91,294,484)	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	245,025,421	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	(571,535,978)	###########	###########	###########
###########	###########	(227,114,702)	###########	###########	###########
###########	###########	131,400,657	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	(390,581,914)	###########	###########	###########
###########	###########	(649,104,183)	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	405,920,171	###########	###########	###########
###########	###########	418,226,550	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	(565,164,600)	###########	###########	###########
###########	###########	###########	###########	###########	###########
###########	###########	###########	###########	###########	###########

TRANSFORMED REGRESSION D-W

SLOPE		-0.593017756
INTERCEPT		-311093143.9
DURBIN-WATSON		2.14
R-SQUARED		

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(91,569,499)				###########	
(152,228,800)	(91,569,499)	(60,659,301)	###########	###########	###########
(193,360,223)	(152,228,800)	(41,131,423)	###########	###########	###########
(362,287,227)	(193,360,223)	(168,927,004)	###########	###########	###########
(64,819,543)	(362,287,227)	297,467,684	###########	###########	###########
(271,509,521)	(64,819,543)	(206,689,978)	###########	###########	###########
(35,301,908)	(271,509,521)	236,207,613	###########	###########	###########
(480,417,982)	(35,301,908)	(445,116,074)	###########	###########	###########
(110,168,815)	(480,417,982)	370,249,167	###########	###########	###########
296,439,423	(110,168,815)	406,608,239	###########	###########	###########
(904,653,211)	296,439,423	###########	###########	###########	###########
(16,639,917)	(904,653,211)	888,013,295	###########	###########	###########
(407,350,051)	(16,639,917)	(390,710,135)	###########	###########	###########
265,087,638	(407,350,051)	672,437,689	###########	###########	###########
(266,401,173)	265,087,638	(531,488,810)	###########	###########	###########
(165,142,987)	(266,401,173)	101,258,186	###########	###########	###########
(50,759,697)	(165,142,987)	114,383,289	###########	###########	###########
(411,687,527)	(50,759,697)	(360,927,830)	###########	###########	###########
(223,452,560)	(411,687,527)	188,234,967	###########	###########	###########
(306,181,851)	(223,452,560)	(82,729,291)	###########	###########	###########
(577,065,909)	(306,181,851)	(270,884,058)	###########	###########	###########
8,608,035	(577,065,909)	585,673,944	###########	###########	###########
6,445,864	8,608,035	(2,162,171)	###########	###########	###########
(647,525,392)	6,445,864	(653,971,256)	###########	###########	###########
461,684,178	(647,525,392)	###########	###########	###########	###########
(538,381,289)	461,684,178	###########	###########	###########	###########
(298,992,619)	(538,381,289)	239,388,670	###########	###########	###########
330,462,613	(298,992,619)	629,455,232	###########	###########	###########
###########	###########	422,032,112	###########	###########	###########

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 8 Admin and General Expenses

R SQUARED, ADJUSTED = 0.93
DURBIN WATSON STATISTIC = 0.01

		Before Cochrane Orcott Adjustment		
A_G_EXP =	Admin General Expense	X-VARIABLE COEFF.	t STATISTIC	
CONSTANT		131	1.452	
CUST =	Cust'S	$ 90.85535	2.885	
DDSO =	Design Day Sendout	$ 130.71	1.4519	#

Line Estimate Results

90.85535	131	(36,384,611)	#N/A
31.496489	90	10,115,517	#N/A
0.932361	3,785,924	#N/A	#N/A
179.1957	26	#N/A	#N/A
5.14E+15	3.73E+14	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	A_G_EXP	CUST	DDSO			
YEAR	ADMIN GENERAL EXPENSE	CUST'S	DESIGN DAY SENDOUT	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	7,704,755	184,779	226,225	46358610	-38653855	7704755
1977	9,157,990	184,321	221,937	45756530	-36598540	9157990
1978	8,713,993	185,232	231,994	47153911	-38439918	8713993
1979	10,536,659	189,091	255,527	50580574	-40043916	10536659
1980	12,479,646	192,620	251,000	50309468	-37829822	12479646
1981	12,907,604	194,544	265,000	52314246	-39406642	12907604
1982	14,682,639	195,276	283,000	54733573	-40050934	14682639
1983	14,238,341	197,836	261,000	52090492	-37852151	14238341
1984	14,366,468	195,276	266,366	52559305	-38192836	14366468
1985	16,309,308	202,626	271,605	53911893	-37602585	16309308
1986	19,433,609	207,842	292,425	57107224	-37673615	19433609
1987	21,137,450	213,657	307,637	59623943	-38486493	21137450
1988	22,006,791	219,556	317,241	61415259	-39408468	22006791
1989	24,896,734	226,230	340,491	65060688	-40163954	24896734
1990	24,327,632	230,551	366,674	68875714	-44548081	24327632
1991	27,845,712	255,326	377,978	72604219	-44758507	27845712
1992	28,227,858	241,232	387,149	72522473	-44294615	28227858
1993	34,806,316	245,550	405,800	75352701	-40546385	34806316
1994	28,583,151	248,710	421,578	77702182	-49119032	28583151
1995	29,152,058	252,841	436,181	79986282	-50834224	29152058
1996	30,397,402	257,364	453,181	82619344	-52221943	30397402
1997	45,086,281	261,170	469,409	85086339	-40000058	45086281
1998	47,644,386	265,545	477,243	86507831	-38863444	47644386
1999	37,395,189	272,086	434,840	81559505	-44164316	37395189
2000	36,195,130	273,808	445,550	83115904	-46920774	36195130
2001	41,107,619	276,749	455,990	84747746	-43640127	41107619
2002	52,474,713	279,495	465,290	86212859	-33738146	52474713
2003	51,427,610	281,227	545,890	96905629	-45478019	51427610
2004	51,843,205	283,032	551,630	97819912	-45976706	51843205

REGRESSION MODEL NO. 8 Admin and General Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =		0.07
DURBIN WATSON STATISTIC =		2.23
After Cochrane Orcott Adjustment		
X-VARIABLE COEFF.	t STATISTIC	
77	0.509	
$ 57.79793	1.307	
76.693010	0.509	

Line Estimate Results

57.79793	77	486,850	#N/A
44.222789	151	1,455,457	#N/A
0.072860	4,501,883	#N/A	#N/A
0.9823	25	#N/A	#N/A
###########	##############	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

RHO 0.98790

YEAR	Y EXPENSE	TRANSFORMED VARIABLES X1 CUST'S	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2
1976													(38,653,855)		
1977	1,546,459	1,778	(1,551)	-	(16,093)	1,562,552	7,595,438	45,756,530	(38,161,092)	7,595,437.9	9,157,990.1	(1,562,552.2)	(36,598,540)	(38,653,855)	##################
1978	(333,189)	3,141	12,743	-	1,158,902	(1,492,091)	10,206,085	47,153,911	(36,947,827)	10,206,084.7	8,713,993.3	1,492,091.4	(38,439,918)	(36,598,540)	##################
1979	1,928,100	6,100	26,340	-	2,372,752	(444,652)	10,981,310	50,580,574	(39,599,264)	10,981,310.1	10,536,658.5	444,651.5	(40,043,916)	(38,439,918)	##################
1980	2,070,476	5,817	(1,435)	-	226,209	1,844,267	10,635,379	50,309,468	(39,674,089)	10,635,378.9	12,479,645.8	(1,844,267.0)	(37,829,822)	(40,043,916)	##################
1981	578,956	4,255	17,037	-	1,552,602	(973,646)	13,881,250	52,314,246	(38,432,996)	13,881,249.8	12,907,603.6	973,646.1	(39,406,642)	(37,829,822)	##################
1982	1,931,211	3,086	21,206	-	1,804,815	126,395	14,556,243	54,733,573	(40,177,329)	14,556,243.2	14,682,638.6	(126,395.4)	(40,050,934)	(39,406,642)	##################
1983	(266,645)	4,923	(18,576)	-	(1,140,035)	873,391	13,364,950	52,090,492	(38,725,542)	13,364,950.3	14,238,340.9	(873,390.6)	(37,852,151)	(40,050,934)	##################
1984	300,405	(166)	8,524	-	644,196	(343,791)	14,710,259	52,559,305	(37,849,045)	14,710,259	14,366,468	343,791	(38,192,836)	(37,852,151)	##################
1985	2,116,667	9,713	8,462	-	1,210,422	906,245	15,403,063	53,911,893	(38,508,830)	15,403,063	16,309,308	(906,245)	(37,602,585)	(38,192,836)	##################
1986	3,321,636	7,668	24,106	-	2,292,037	1,029,599	18,404,010	57,107,224	(38,703,214)	18,404,010	19,433,609	(1,029,599)	(37,673,615)	(37,602,585)	##################
1987	1,938,979	8,330	18,750	-	1,919,531	19,448	21,118,002	59,623,943	(38,505,941)	21,118,002	21,137,450	(19,448)	(38,486,493)	(37,673,615)	##################
1988	1,125,094	8,484	13,326	-	1,512,474	(387,380)	22,394,171	61,415,259	(39,021,088)	22,394,171	22,006,791	387,380	(39,408,468)	(38,486,493)	##################
1989	3,156,214	9,331	27,088	-	2,616,858	539,357	24,357,377	65,060,688	(40,703,311)	24,357,377	24,896,734	(539,357)	(40,163,954)	(39,408,468)	##################
1990	(267,863)	7,058	30,303	-	2,732,042	(2,999,905)	27,327,537	68,875,714	(41,548,177)	27,327,537	24,327,632	2,999,905	(44,548,081)	(40,163,954)	##################
1991	3,812,433	27,564	15,741	-	2,800,439	1,011,994	26,833,718	72,604,219	(45,770,501)	26,833,718	27,845,712	(1,011,994)	(44,758,507)	(44,548,081)	##################
1992	719,066	(11,005)	13,744	-	418,130	300,936	27,926,922	72,522,473	(44,595,551)	27,926,922	28,227,858	(300,936)	(44,294,615)	(44,758,507)	##################
1993	6,920,002	7,237	23,335	-	2,208,004	4,711,997	30,094,319	75,352,701	(45,258,382)	30,094,319	34,806,316	(4,711,997)	(40,546,385)	(44,294,615)	##################
1994	(5,802,026)	6,131	20,688	-	1,941,062	(7,743,088)	36,326,238	77,702,182	(41,375,944)	36,326,238	28,583,151	7,743,088	(49,119,032)	(40,546,385)	##################
1995	914,750	7,140	19,704	-	1,923,911	(1,009,161)	30,161,219	79,986,282	(49,825,063)	30,161,219	29,152,058	1,009,161	(50,834,224)	(49,119,032)	##################
1996	1,598,070	7,582	22,278	-	2,146,859	(548,790)	30,946,191	82,619,344	(51,673,153)	30,946,191	30,397,402	548,790	(52,221,943)	(50,834,224)	##################
1997	15,056,673	6,920	21,711	-	2,065,140	12,991,533	32,094,748	85,086,339	(52,991,591)	32,094,748	45,086,281	(12,991,533)	(40,000,058)	(52,221,943)	##################
1998	3,103,628	7,535	13,514	-	1,471,987	1,631,642	46,012,745	86,507,831	(40,495,086)	46,012,745	47,644,386	(1,631,642)	(38,863,444)	(40,000,058)	##################
1999	(9,672,723)	9,754	(36,629)	-	(2,245,332)	(7,427,391)	44,822,580	81,559,505	(36,736,925)	44,822,580	37,395,189	7,427,391	(44,164,316)	(38,863,444)	##################
2000	(747,595)	5,014	15,971	-	1,514,785	(2,262,379)	38,457,510	83,115,904	(44,658,395)	38,457,510	36,195,130	2,262,379	(46,920,774)	(44,164,316)	##################
2001	5,350,433	6,254	15,831	-	1,575,665	3,774,768	37,332,851	84,747,746	(47,414,895)	37,332,851	41,107,619	(3,774,768)	(43,640,127)	(46,920,774)	##################
2002	11,864,477	6,095	14,817	-	1,488,708	10,375,768	42,098,945	86,212,859	(44,113,914)	42,098,945	52,474,713	(10,375,768)	(33,738,146)	(43,640,127)	##################
2003	(412,184)	5,114	86,230	-	6,908,863	(7,321,047)	58,748,657	96,905,629	(38,156,972)	58,748,657	51,427,610	7,321,047	(45,478,019)	(33,738,146)	##################
2004	1,037,845	5,208	12,345	-	1,247,848	(210,003)	52,053,208	97,819,912	(45,766,704)	52,053,208	51,843,205	210,003	(45,976,706)	(45,478,019)	##################
												SUM	###########	###########	##################

E(t)*E(t-1)
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ORIGINAL REGRESSION D-W

SLOPE	0.49130923
INTERCEPT	-21327349.02
DURBIN-WATSON	0.01
R-SQUARED	0.932

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(38,653,855)				###########	
(36,598,540)	(38,653,855)	2,055,315	###########	###########	###########
(38,439,918)	(36,598,540)	(1,841,379)	###########	###########	###########
(40,043,916)	(38,439,918)	(1,603,997)	###########	###########	###########
(37,829,822)	(40,043,916)	2,214,093	###########	###########	###########
(39,406,642)	(37,829,822)	(1,576,820)	###########	###########	###########
(40,050,934)	(39,406,642)	(644,292)	###########	###########	###########
(37,852,151)	(40,050,934)	2,198,783	###########	###########	###########
(38,192,836)	(37,852,151)	(340,685)	###########	###########	###########
(37,602,585)	(38,192,836)	590,252	###########	###########	###########
(37,673,615)	(37,602,585)	(71,030)	###########	###########	###########
(38,486,493)	(37,673,615)	(812,877)	###########	###########	###########
(39,408,468)	(38,486,493)	(921,975)	###########	###########	###########
(40,163,954)	(39,408,468)	(755,486)	###########	###########	###########
(44,548,081)	(40,163,954)	(4,384,127)	###########	###########	###########
(44,758,507)	(44,548,081)	(210,425)	###########	###########	###########
(44,294,615)	(44,758,507)	463,892	###########	###########	###########
(40,546,385)	(44,294,615)	3,748,230	###########	###########	###########
(49,119,032)	(40,546,385)	(8,572,647)	###########	###########	###########
(50,834,224)	(49,119,032)	(1,715,193)	###########	###########	###########
(52,221,943)	(50,834,224)	(1,387,718)	###########	###########	###########
(40,000,058)	(52,221,943)	12,221,885	###########	###########	###########
(38,863,444)	(40,000,058)	1,136,613	###########	###########	###########
(44,164,316)	(38,863,444)	(5,300,872)	###########	###########	###########
(46,920,774)	(44,164,316)	(2,756,458)	###########	###########	###########
(43,640,127)	(46,920,774)	3,280,647	###########	###########	###########
(33,738,146)	(43,640,127)	9,901,981	###########	###########	###########
(45,478,019)	(33,738,146)	(11,739,873)	###########	###########	###########
(45,976,706)	(45,478,019)	(498,687)	###########	###########	###########
###########	###########	(7,322,852)	###########	###########	###########

TRANSFORMED REGRESSION D-W

SLOPE	-0.122496373
INTERCEPT	297979.2563
DURBIN-WATSON	2.23
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1,562,552				###########	
(1,492,091)	1,562,552	(3,054,644)	###########	###########	###########
(444,652)	(1,492,091)	1,047,440	###########	###########	###########
1,844,267	(444,652)	2,288,919	###########	###########	###########
(973,646)	1,844,267	(2,817,913)	###########	###########	###########
126,395	(973,646)	1,100,042	###########	###########	###########
873,391	126,395	746,995	###########	###########	###########
(343,791)	873,391	(1,217,182)	###########	###########	###########
906,245	(343,791)	1,250,036	###########	###########	###########
1,029,599	906,245	123,353	###########	###########	###########
19,448	1,029,599	(1,010,151)	###########	378,230,494	###########
(387,380)	19,448	(406,828)	###########	###########	###########
539,357	(387,380)	926,737	###########	###########	###########
(2,999,905)	539,357	(3,539,261)	###########	###########	###########
1,011,994	(2,999,905)	4,011,899	###########	###########	###########
300,936	1,011,994	(711,058)	###########	###########	###########
4,711,997	300,936	4,411,061	###########	###########	###########
(7,743,088)	4,711,997	(12,455,085)	###########	###########	###########
(1,009,161)	(7,743,088)	6,733,926	###########	###########	###########
(548,790)	(1,009,161)	460,371	###########	###########	###########
12,991,533	(548,790)	13,540,323	###########	###########	###########
1,631,642	12,991,533	(11,359,891)	###########	###########	###########
(7,427,391)	1,631,642	(9,059,032)	###########	###########	###########
(2,262,379)	(7,427,391)	5,165,011	###########	###########	###########
3,774,768	(2,262,379)	6,037,147	###########	###########	###########
10,375,768	3,774,768	6,601,000	###########	###########	###########
(7,321,047)	10,375,768	(17,696,815)	###########	###########	###########
(210,003)	(7,321,047)	7,111,044	###########	###########	###########
8,536,569	8,746,571	(1,772,555)	###########	###########	###########

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 9 Admin and General Expenses

R SQUARED, ADJUSTED = 0.93
DURBIN WATSON STATISTIC = 1.44

Before Cochrane Orcott Adjustment

		X-VARIABLE COEFF.	t STATISTIC
A_G_EXP =	Admin General Expense		
CONSTANT		-22225252	-8.107
DDSO =	Design Day Sendout	$ 135.38447	18.500
=			#

Line Estimate Results

135.38447	(22,225,252)	#N/A	#N/A
7.318212	2,741,622	#N/A	#N/A
0.926876	3,862,832	#N/A	#N/A
342.2376	27	#N/A	#N/A
5.11E+15	4.03E+14	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	A_G_EXP	DDSO			
YEAR	ADMIN GENERAL EXPENSE	DESIGN DAY SENDOUT	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	7,704,755	226,225	8402032	-697277	7704755
1977	9,157,990	221,937	7821531	1336460	9157990
1978	8,713,993	231,994	9183133	-469139	8713993
1979	10,536,659	255,527	12369135	-1832477	10536659
1980	12,479,646	251,000	11756250	723396	12479646
1981	12,907,604	265,000	13651632	-744029	12907604
1982	14,682,639	283,000	16088553	-1405914	14682639
1983	14,238,341	261,000	13110095	1128246	14238341
1984	14,366,468	266,366	13836568	529901	14366468
1985	16,309,308	271,605	14545847	1763461	16309308
1986	19,433,609	292,425	17364552	2069057	19433609
1987	21,137,450	307,637	19424020	1713430	21137450
1988	22,006,791	317,241	20724253	1282539	22006791
1989	24,896,734	340,491	23871941	1024792	24896734
1990	24,327,632	366,674	27416713	-3089081	24327632
1991	27,845,712	377,978	28947099	-1101387	27845712
1992	28,227,858	387,149	30188710	-1960852	28227858
1993	34,806,316	405,800	32713766	2092550	34806316
1994	28,583,151	421,578	34849862	-6266711	28583151
1995	29,152,058	436,181	36826881	-7674823	29152058
1996	30,397,402	453,181	39128417	-8731015	30397402
1997	45,086,281	469,409	41325436	3760845	45086281
1998	47,644,386	477,243	42386038	5258348	47644386
1999	37,395,189	434,840	36645331	749858	37395189
2000	36,195,130	445,550	38095298	-1900168	36195130
2001	41,107,619	455,990	39508712	1598907	41107619
2002	52,474,713	465,290	40767788	11706925	52474713
2003	51,427,610	545,890	51679776	-252166	51427610
2004	51,843,205	551,630	52456883	-613677	51843205

REGRESSION MODEL NO. 9 Admin and General Expenses WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED =		0.87
DURBIN WATSON STATISTIC =		1.85
After Cochrane Orcott Adjustment		
X-VARIABLE COEFF.	t STATISTIC	
-15429326	-5.555	
$ 133.12857	13.286	
-15429325.833056	-5.555	

Line Estimate Results

133.12857	(15,429,326)	#N/A	#N/A
10.019989	2,777,321	#N/A	#N/A
0.871621	3,775,576	#N/A	#N/A
176.5257	26	#N/A	#N/A
###########	##############	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

		TRANSFORMED VARIABLES									ORIGINAL		RHO	0.27774	
	Y	X1	X2	X3	ESTIMATED		ADJUSTED FORECAST	ORIGINAL FORECAST		ADJUSTED FORECAST	ESTIMATED + RESIDUAL			LAGGED	
YEAR	EXPENSE	SENDOUT	N/A	N/A	(Y)'t	RESIDUAL	(Y)	(Y)'	DIFFERENCE	(Y)	(Y)	DIFFERENCE	ERROR	ERROR	ERROR^2
1976													(697,277)		
1977	7,018,082	159,105	-	-	5,752,150	1,265,932	7,892,058	7,821,531	70,527	7,892,057.9	9,157,990.1	(1,265,932.1)	1,336,460	(697,277)	1,786,124,214,655
1978	6,170,465	170,354	-	-	7,249,605	(1,079,139)	9,793,133	9,183,133	610,000	9,793,132.7	8,713,993.3	1,079,139.4	(469,139)	1,336,460	220,091,802,201
1979	8,116,446	191,093	-	-	10,010,651	(1,894,206)	12,430,864	12,369,135	61,729	12,430,864.1	10,536,658.5	1,894,205.5	(1,832,477)	(469,139)	3,357,971,576,897
1980	9,553,208	180,030	-	-	8,537,847	1,015,362	11,464,284	11,756,250	(291,966)	11,464,284.1	12,479,645.8	(1,015,361.7)	723,396	(1,832,477)	523,301,644,688
1981	9,441,523	195,288	-	-	10,569,032	(1,127,509)	14,035,112	13,651,632	383,480	14,035,112.4	12,907,603.6	1,127,508.8	(744,029)	723,396	553,578,917,112
1982	11,097,698	209,399	-	-	12,447,697	(1,349,999)	16,032,638	16,088,553	(55,915)	16,032,637.8	14,682,638.6	1,349,999.2	(1,405,914)	(744,029)	1,976,595,035,034
1983	10,160,404	182,400	-	-	8,853,319	1,307,085	12,931,256	13,110,095	(178,839)	12,931,255.9	14,238,340.9	(1,307,085.0)	1,128,246	(1,405,914)	1,272,939,729,049
1984	10,411,930	193,876	-	-	10,381,136	30,794	14,335,674	13,836,568	499,106	14,335,674	14,366,468	(30,794)	529,901	1,128,246	280,794,613,936
1985	12,319,184	197,625	-	-	10,880,189	1,438,995	14,870,313	14,545,847	324,466	14,870,313	16,309,308	(1,438,995)	1,763,461	529,901	3,109,796,012,607
1986	14,903,883	216,990	-	-	13,458,214	1,445,669	17,987,940	17,364,552	623,388	17,987,940	19,433,609	(1,445,669)	2,069,057	1,763,461	4,280,998,604,530
1987	15,739,986	226,419	-	-	14,713,548	1,026,438	20,111,012	19,424,020	686,992	20,111,012	21,137,450	(1,026,438)	1,713,430	2,069,057	2,935,843,824,390
1988	16,136,104	231,798	-	-	15,429,651	706,453	21,300,339	20,724,253	576,086	21,300,339	22,006,791	(706,453)	1,282,539	1,713,430	1,644,905,909,625
1989	18,784,597	252,381	-	-	18,169,783	614,814	24,281,920	23,871,941	409,979	24,281,920	24,896,734	(614,814)	1,024,792	1,282,539	1,050,199,566,122
1990	17,412,846	272,106	-	-	20,795,821	(3,382,975)	27,710,607	27,416,713	293,894	27,710,607	24,327,632	3,382,975	(3,089,081)	1,024,792	9,542,419,797,145
1991	21,088,988	276,138	-	-	21,332,591	(243,603)	28,089,315	28,947,099	(857,784)	28,089,315	27,845,712	243,603	(1,101,387)	(3,089,081)	1,213,053,200,544
1992	20,494,027	282,170	-	-	22,135,548	(1,641,521)	29,869,379	30,188,710	(319,331)	29,869,379	28,227,858	1,641,521	(1,960,852)	(1,101,387)	3,844,939,185,816
1993	26,966,348	298,274	-	-	24,279,432	2,686,916	32,119,400	32,713,766	(594,366)	32,119,400	34,806,316	(2,686,916)	2,092,550	(1,960,852)	4,378,767,246,855
1994	18,916,090	308,872	-	-	25,690,315	(6,774,224)	35,357,375	34,849,862	507,513	35,357,375	28,583,151	6,774,224	(6,266,711)	2,092,550	39,271,669,837,927
1995	21,213,412	319,092	-	-	27,051,000	(5,837,589)	34,989,647	36,826,881	(1,837,234)	34,989,647	29,152,058	5,837,589	(7,674,823)	(6,266,711)	58,902,909,286,621
1996	22,300,748	332,037	-	-	28,774,241	(6,473,493)	36,870,895	39,128,417	(2,257,522)	36,870,895	30,397,402	6,473,493	(8,731,015)	(7,674,823)	76,230,630,842,309
1997	36,643,747	343,543	-	-	30,306,077	6,337,670	38,748,611	41,325,436	(2,576,825)	38,748,611	45,086,281	(6,337,670)	3,760,845	(8,731,015)	14,143,952,186,772
1998	35,122,183	346,870	-	-	30,748,977	4,373,206	43,271,181	42,386,038	885,142	43,271,181	47,644,386	(4,373,206)	5,258,348	3,760,845	27,650,226,321,860
1999	24,162,500	302,291	-	-	24,814,264	(651,764)	38,046,953	36,645,331	1,401,622	38,046,953	37,395,189	651,764	749,858	5,258,348	562,287,545,726
2000	25,809,040	324,778	-	-	27,807,920	(1,998,880)	38,194,010	38,095,298	98,712	38,194,010	36,195,130	1,998,880	(1,900,168)	749,858	3,610,638,101,089
2001	31,054,832	332,244	-	-	28,801,781	2,253,051	38,854,568	39,508,712	(654,144)	38,854,568	41,107,619	(2,253,051)	1,598,907	(1,900,168)	2,556,503,464,873
2002	41,057,537	338,644	-	-	29,653,858	11,403,679	41,071,033	40,767,788	303,246	41,071,033	52,474,713	(11,403,679)	11,706,925	1,598,907	137,052,097,823,954
2003	36,853,353	416,661	-	-	40,040,154	(3,186,801)	54,614,411	51,679,776	2,934,635	54,614,411	51,427,610	3,186,801	(252,166)	11,706,925	63,587,607,418
2004	37,559,769	400,015	-	-	37,824,130	(264,361)	52,107,567	52,456,883	(349,316)	52,107,567	51,843,205	264,361	(613,677)	(252,166)	376,599,802,454
												SUM	697,277	613,677	402,393,423,702,208

E(t)*E(t-1)
(931,882,640,335)
(626,985,882,901)
859,687,161,761
(1,325,606,294,873)
(538,227,421,997)
1,046,040,792,255
(1,586,217,623,258)
597,858,360,971
934,459,186,257
3,648,702,836,673
3,545,185,935,227
2,197,541,093,240
1,314,336,133,796
(3,165,666,617,116)
3,402,273,192,420
2,159,656,404,443
(4,103,180,933,495)
(13,113,409,229,320)
48,095,900,095,513
67,008,998,898,405
(32,835,992,413,830)
19,775,830,679,135
3,943,016,345,043
(1,424,856,777,492)
(3,038,191,701,627)
18,718,284,188,329
(2,952,086,548,897)
154,748,442,293
111,760,215,660,617

ORIGINAL REGRESSION D-W

SLOPE	0.277634359
INTERCEPT	18817.82808
DURBIN-WATSON	1.44
R-SQUARED	0.927

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
(697,277)				###########	
1,336,460	(697,277)	2,033,737	###########	###########	###########
(469,139)	1,336,460	(1,805,599)	###########	###########	###########
(1,832,477)	(469,139)	(1,363,337)	###########	###########	###########
723,396	(1,832,477)	2,555,873	###########	###########	###########
(744,029)	723,396	(1,467,425)	###########	###########	###########
(1,405,914)	(744,029)	(661,885)	###########	###########	###########
1,128,246	(1,405,914)	2,534,161	###########	###########	###########
529,901	1,128,246	(598,346)	###########	###########	###########
1,763,461	529,901	1,233,561	###########	###########	###########
2,069,057	1,763,461	305,596	###########	###########	###########
1,713,430	2,069,057	(355,627)	###########	###########	###########
1,282,539	1,713,430	(430,892)	###########	###########	###########
1,024,792	1,282,539	(257,746)	###########	###########	###########
(3,089,081)	1,024,792	(4,113,873)	###########	###########	###########
(1,101,387)	(3,089,081)	1,987,694	###########	###########	###########
(1,960,852)	(1,101,387)	(859,465)	###########	###########	###########
2,092,550	(1,960,852)	4,053,402	###########	###########	###########
(6,266,711)	2,092,550	(8,359,262)	###########	###########	###########
(7,674,823)	(6,266,711)	(1,408,112)	###########	###########	###########
(8,731,015)	(7,674,823)	(1,056,192)	###########	###########	###########
3,760,845	(8,731,015)	12,491,860	###########	###########	###########
5,258,348	3,760,845	1,497,504	###########	###########	###########
749,858	5,258,348	(4,508,490)	###########	###########	###########
(1,900,168)	749,858	(2,650,026)	###########	###########	###########
1,598,907	(1,900,168)	3,499,075	###########	###########	###########
11,706,925	1,598,907	10,108,018	###########	###########	###########
(252,166)	11,706,925	(11,959,091)	###########	###########	###########
(613,677)	(252,166)	(361,511)	###########	###########	###########
697,277	613,677	83,600	###########	###########	###########

TRANSFORMED REGRESSION D-W

SLOPE	0.072557682
INTERCEPT	-47596.7993
DURBIN-WATSON	1.85
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1,265,932				###########	
(1,079,139)	1,265,932	(2,345,072)	###########	###########	###########
(1,894,206)	(1,079,139)	(815,066)	###########	###########	###########
1,015,362	(1,894,206)	2,909,567	###########	###########	###########
(1,127,509)	1,015,362	(2,142,871)	###########	###########	###########
(1,349,999)	(1,127,509)	(222,490)	###########	###########	###########
1,307,085	(1,349,999)	2,657,084	###########	###########	###########
30,794	1,307,085	(1,276,291)	###########	948,275,951	###########
1,438,995	30,794	1,408,201	###########	###########	###########
1,445,669	1,438,995	6,674	44,539,862	###########	###########
1,026,438	1,445,669	(419,231)	###########	###########	###########
706,453	1,026,438	(319,986)	###########	###########	###########
614,814	706,453	(91,639)	###########	###########	###########
(3,382,975)	614,814	(3,997,788)	###########	###########	###########
(243,603)	(3,382,975)	3,139,371	###########	###########	###########
(1,641,521)	(243,603)	(1,397,918)	###########	###########	###########
2,686,916	(1,641,521)	4,328,437	###########	###########	###########
(6,774,224)	2,686,916	(9,461,140)	###########	###########	###########
(5,837,589)	(6,774,224)	936,636	###########	###########	###########
(6,473,493)	(5,837,589)	(635,904)	###########	###########	###########
6,337,670	(6,473,493)	12,811,163	###########	###########	###########
4,373,206	6,337,670	(1,964,464)	###########	###########	###########
(651,764)	4,373,206	(5,024,970)	###########	###########	###########
(1,998,880)	(651,764)	(1,347,116)	###########	###########	###########
2,253,051	(1,998,880)	4,251,931	###########	###########	###########
11,403,679	2,253,051	9,150,629	###########	###########	###########
(3,186,801)	11,403,679	(14,590,480)	###########	###########	###########
(264,361)	(3,186,801)	2,922,440	###########	###########	###########
0	264,361	(1,530,293)	###########	###########	###########

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BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 10 Distribution Footoge vs Demand

R SQUARED, ADJUSTED = 0.96
DURBIN WATSON STATISTIC = 0.91

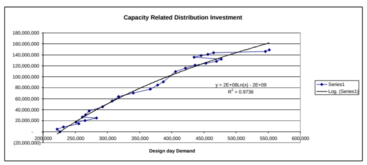
		Before Cochrane Orcott Adjustment X-VARIABLE COEFF.	t STATISTIC
DPI =	Distribution Footage		
CONSTANT		-1387840	-15.720
DDD =	Design Day Demand	6.13	26.012

Line Estimate Results

6.12989	(1,387,840)	#N/A	#N/A
0.235658	88,284	#N/A	#N/A
0.961627	124,389	#N/A	#N/A
676.6172	27	#N/A	#N/A
1.05E+13	4.18E+11	#N/A	#N/A

Format of Line Estimate Results
Slope Constant
Std Err X Std Err b
R^2 Std Err Y
F Deg of Free
SumSq Reg SumSq Resid

YEAR	DPI DISTR PLANT FOOTAGE	DDD DESIGN DAY DEMAND	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	14,131	226,225	-1107	15239	14131
1977	23,802	221,937	-27391	51194	23802
1978	48,614	231,994	34259	14355	48614
1979	94,915	255,527	178514	-83599	94915
1980	122,573	251,000	150764	-28191	122573
1981	140,947	265,000	236582	-95635	140947
1982	174,506	283,000	346920	-172414	174506
1983	191,443	261,000	212063	-20619	191443
1984	236,330	266,366	244956	-8626	236330
1985	317,250	271,605	277070	40180	317250
1986	397,357	292,425	404695	-7337	397357
1987	492,446	307,637	497943	-5496	492446
1988	620,363	317,241	556814	63549	620363
1989	732,268	340,491	699334	32933	732268
1990	806,702	366,674	859833	-53131	806702
1991	883,467	377,978	929125	-45658	883467
1992	985,517	387,149	985343	174	985517
1993	1,080,137	405,800	1099671	-19534	1080137
1994	1,169,204	421,578	1196389	-27185	1169204
1995	1,270,542	436,181	1285904	-15361	1270542
1996	1,341,707	453,181	1390112	-48405	1341707
1997	1,421,593	469,409	1489588	-67994	1421593
1998	1,491,841	477,243	1537609	-45768	1491841
1999	1,546,381	434,840	1277683	268697	1546381
2000	1,595,371	445,550	1343335	252036	1595371
2001	1,645,403	455,990	1407331	238072	1645403
2002	1,687,172	465,290	1464339	222833	1687172
2003	1,722,612	545,890	1958408	-235796	1722612
2004	1,775,084	551,630	1993594	-218510	1775084



REGRESSION MODEL NO. 10 Distribution Footoge vs Demand WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.90
DURBIN WATSON STATISTIC = 1.42

	After Cochrane Orcott Adjustment X-VARIABLE COEFF.	t STATISTIC
CONSTANT	-621077	-8.210
DDD	5.63	14.966

Line Estimate Results

5.63232	(621,077)	#N/A	#N/A
0.376332	75,653	#N/A	#N/A
0.895996	105,207	#N/A	#N/A
223.9914	26	#N/A	#N/A
2.48E+12	2.88E+11	#N/A	#N/A

Format of Line Estimate Results
Slope Constant
Std Err X Std Err b
R^2 Std Err Y
F Deg of Free
SumSq Reg SumSq Resid

RHO 0.48607

YEAR	TRANSFORMED VARIABLES Y FOOTAGE	X1 DEMAND	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ORIGINAL ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2	E(t)*E(t-1)
1976													15,239			
1977	16,933	111,975	-	-	9,603	7,331	16,472	(27,391)	43,863	16,471.8	23,802.3	(7,330.6)	51,194	15,239	2,620,782,108	780,136,191
1978	37,044	124,117	-	-	77,988	(40,943)	89,557	34,259	55,298	89,557.2	48,614.2	40,943.1	14,355	51,194	206,072,195	734,894,770
1979	71,285	142,761	-	-	182,999	(111,714)	206,629	178,514	28,115	206,628.9	94,915.0	111,713.9	(83,599)	14,355	6,988,752,873	(1,200,078,184)
1980	76,437	126,795	-	-	93,075	(16,637)	139,210	150,764	(11,553)	139,210.2	122,572.9	16,637.4	(28,191)	(83,599)	794,724,189	2,356,720,381
1981	81,367	142,996	-	-	184,321	(102,953)	243,900	236,582	7,318	243,900.1	140,946.8	102,953.3	(95,635)	(28,191)	9,146,142,413	2,696,045,365
1982	105,996	154,191	-	-	247,374	(141,379)	315,885	346,920	(31,035)	315,884.8	174,506.3	141,378.6	(172,414)	(95,635)	29,726,607,349	16,488,898,819
1983	106,621	123,441	-	-	74,185	32,436	159,007	212,063	(53,055)	159,007.3	191,443.3	(32,436.0)	(20,619)	(172,414)	425,157,537	3,555,065,562
1984	143,274	139,501	-	-	164,637	(21,363)	257,693	244,956	12,737	257,693	236,330	21,363	(8,626)	(20,619)	74,404,175	177,858,077
1985	202,376	142,132	-	-	179,454	22,922	294,328	277,070	17,258	294,328	317,250	(22,922)	40,180	(8,626)	1,614,393,743	(346,579,910)
1986	243,151	160,405	-	-	282,376	(39,226)	436,583	404,695	31,888	436,583	397,357	39,226	(7,337)	40,180	53,835,049	(294,806,660)
1987	299,301	165,497	-	-	311,056	(11,755)	504,201	497,943	6,258	504,201	492,446	11,755	(5,496)	(7,337)	30,210,496	40,328,446
1988	380,998	167,707	-	-	323,503	57,495	562,867	556,814	6,053	562,867	620,363	(57,495)	63,549	(5,496)	4,038,417,649	(349,288,704)
1989	430,726	186,289	-	-	428,161	2,565	729,702	699,334	30,368	729,702	732,268	(2,565)	32,933	63,549	1,084,615,090	2,092,875,707
1990	450,767	201,171	-	-	511,980	(61,213)	867,915	859,833	8,082	867,915	806,702	61,213	(53,131)	32,933	2,822,865,487	(1,749,777,845)
1991	491,351	199,748	-	-	503,966	(12,615)	896,082	929,125	(33,043)	896,082	883,467	12,615	(45,658)	(53,131)	2,084,688,838	2,425,859,883
1992	556,087	203,424	-	-	524,673	31,414	954,102	985,343	(31,240)	954,102	985,517	(31,414)	174	(45,658)	30,258	(7,942,253)
1993	601,104	217,617	-	-	604,614	(3,509)	1,083,647	1,099,671	(16,025)	1,083,647	1,080,137	3,509	(19,534)	174	381,579,842	(3,397,941)
1994	644,178	224,330	-	-	642,419	1,759	1,167,445	1,196,389	(28,944)	1,167,445	1,169,204	(1,759)	(27,185)	(19,534)	739,019,689	531,032,029
1995	702,224	231,263	-	-	681,472	20,751	1,249,791	1,285,904	(36,113)	1,249,791	1,270,542	(20,751)	(15,361)	(27,185)	235,974,123	417,599,716
1996	724,130	241,165	-	-	737,243	(13,112)	1,354,819	1,390,112	(35,293)	1,354,819	1,341,707	13,112	(48,405)	(15,361)	2,343,065,188	743,574,308
1997	769,426	249,130	-	-	782,103	(12,677)	1,434,270	1,489,588	(55,318)	1,434,270	1,421,593	12,677	(67,994)	(48,405)	4,623,228,674	3,291,280,323
1998	800,843	249,076	-	-	781,799	19,044	1,472,797	1,537,609	(64,812)	1,472,797	1,491,841	(19,044)	(45,768)	(67,994)	2,094,721,708	3,111,973,243
1999	821,237	202,865	-	-	521,524	299,713	1,246,668	1,277,683	(31,015)	1,246,668	1,546,381	(299,713)	268,697	(45,768)	72,198,269,300	(12,297,775,488)
2000	843,717	234,186	-	-	697,934	145,783	1,449,588	1,343,335	106,253	1,449,588	1,595,371	(145,783)	252,036	268,697	63,522,108,676	67,721,387,380
2001	869,936	239,420	-	-	727,414	142,522	1,502,881	1,407,331	95,550	1,502,881	1,645,403	(142,522)	238,072	252,036	56,678,325,232	60,002,722,730
2002	887,386	243,646	-	-	751,213	136,173	1,550,999	1,464,339	86,660	1,550,999	1,687,172	(136,173)	222,833	238,072	49,654,496,141	53,050,293,887
2003	902,523	319,725	-	-	1,179,717	(277,194)	1,999,806	1,958,408	41,398	1,999,806	1,722,612	277,194	(235,796)	222,833	55,599,975,956	(52,543,208,805)
2004	937,769	286,288	-	-	991,387	(53,618)	1,828,702	1,993,594	(164,892)	1,828,702	1,775,084	53,618	(218,510)	(235,796)	47,746,611,821	51,523,882,513
												SUM	(15,239)	218,510	417,529,075,796	202,949,573,539

ORIGINAL REGRESSION D-W
SLOPE 0.551352933
INTERCEPT -4846.96665
DURBIN-WATSON 0.91
R-SQUARED 0.962

YEAR	ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1976	15,239				232,225,516	
1977	51,194	15,239	35,955	##########	##########	780,136,191
1978	14,355	51,194	(36,838)	##########	206,072,195	734,894,770
1979	(83,599)	14,355	(97,954)	##########	##########	##########
1980	(28,191)	(83,599)	55,408	##########	794,724,189	##########
1981	(95,635)	(28,191)	(67,445)	##########	##########	##########
1982	(172,414)	(95,635)	(76,779)	##########	##########	##########
1983	(20,619)	(172,414)	151,795	##########	425,157,537	##########
1984	(8,626)	(20,619)	11,994	143,845,557	74,404,175	177,858,077
1985	40,180	(8,626)	48,805	##########	##########	##########
1986	(7,337)	40,180	(47,517)	##########	53,835,049	##########
1987	(5,496)	(7,337)	1,841	3,388,654	30,210,496	40,328,446
1988	63,549	(5,496)	69,045	##########	##########	##########
1989	32,933	63,549	(30,615)	937,281,326	##########	##########
1990	(53,131)	32,933	(86,064)	##########	##########	##########
1991	(45,658)	(53,131)	7,472	55,834,559	##########	##########
1992	174	(45,658)	45,832	##########	30,258	(7,942,253)
1993	(19,534)	174	(19,708)	388,405,982	381,579,842	(3,397,941)
1994	(27,185)	(19,534)	(7,651)	58,535,472	739,019,689	531,032,029
1995	(15,361)	(27,185)	11,823	139,794,380	235,974,123	417,599,716
1996	(48,405)	(15,361)	(33,044)	##########	##########	743,574,308
1997	(67,994)	(48,405)	(19,589)	383,733,217	##########	##########
1998	(45,768)	(67,994)	22,226	494,003,896	##########	##########
1999	268,697	(45,768)	314,465	##########	##########	##########
2000	252,036	268,697	(16,661)	277,603,216	##########	##########
2001	238,072	252,036	(13,964)	194,988,449	##########	##########
2002	222,833	238,072	(15,239)	232,233,599	##########	##########
2003	(235,796)	222,833	(458,629)	##########	##########	##########
2004	(218,510)	(235,796)	17,286	298,822,751	##########	##########
	(15,239)	218,510	(233,749)	##########	##########	##########

TRANSFORMED REGRESSION D-W
SLOPE 0.288535264
INTERCEPT -844.489951
DURBIN-WATSON 1.42
R-SQUARED

YEAR	ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1977	7,331				53,737,362	
1978	(40,943)	7,331	(48,274)	##########	##########	##########
1979	(111,714)	(40,943)	(70,771)	##########	##########	##########
1980	(16,637)	(111,714)	95,077	##########	276,802,490	##########
1981	(102,953)	(16,637)	(86,316)	##########	##########	##########
1982	(141,379)	(102,953)	(38,425)	##########	##########	##########
1983	32,436	(141,379)	173,815	##########	##########	##########
1984	(21,363)	32,436	(53,799)	##########	456,371,405	##########
1985	22,922	(21,363)	44,285	##########	525,404,059	##########
1986	(39,226)	22,922	(62,147)	##########	##########	##########
1987	(11,755)	(39,226)	27,471	754,659,725	138,168,475	461,077,415
1988	57,495	(11,755)	69,250	##########	##########	##########
1989	2,565	57,495	(54,930)	##########	6,579,855	147,482,344
1990	(61,213)	2,565	(63,778)	##########	##########	##########
1991	(12,615)	(61,213)	48,598	##########	159,146,547	772,222,900
1992	31,414	(12,615)	44,030	##########	986,855,323	##########
1993	(3,509)	31,414	(34,924)	##########	12,316,103	##########
1994	1,759	(3,509)	5,269	27,757,471	3,094,452	(6,173,458)
1995	20,751	1,759	18,992	360,711,020	430,624,715	36,504,073
1996	(13,112)	20,751	(33,864)	##########	171,935,316	##########
1997	(12,677)	(13,112)	436	189,780	160,700,585	166,223,061
1998	19,044	(12,677)	31,721	##########	362,685,205	##########
1999	299,713	19,044	280,669	##########	##########	##########
2000	145,783	299,713	(153,930)	##########	##########	##########
2001	142,522	145,783	(3,261)	10,632,623	##########	##########
2002	136,173	142,522	(6,349)	40,313,889	##########	##########
2003	(277,194)	136,173	(413,367)	##########	##########	##########
2004	(53,618)	(277,194)	223,576	##########	##########	##########
	(0)	53,618	(60,948)	##########	##########	##########

7/25/2005 1:25 PM

BAY STATE GAS COMPANY
MARGINAL COST STUDY REGRESSIONS
COCHRANE ORCOTT ADJUSTMENT WORKPAPERS

REGRESSION MODEL NO. 1E Second Order Distribution Capacity-Re

R SQUARED, ADJUSTED = 0.98
DURBIN WATSON STATISTIC = 1.00

DPI = Distribution Plant Capacity-related Investment

		Before Cochrane Orcott Adjustment X-VARIABLE COEFF.	t STATISTIC
CONSTANT		-205561683	-9.167
DDD^2 =	Design Day Demand Squared	(0.00081)	(4.79)
DDD =	Design Day Demand	1,085.45	8.57

Line Estimate Results

1,085.45	(0.00081)	-2.056E+08	#N/A
126.59	0.00017	2.242E+07	#N/A
0.98	7,649,091	#N/A	#N/A
567.22	26	#N/A	#N/A
6.64E+16	1.52E+15	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

YEAR	DPI DISTR PLANT INVEST	DDD^2 DESIGN DAY DMD Squared	DDD DESIGN DAY DEMAND	ESTIMATED (Y)'	RESIDUAL	ESTIMATED + RESIDUAL (Y)
1976	-	5.118E+10	226,225	-1425417	1425417	0
1977	3,922,041	4.926E+10	221,937	-4524415	8446456	3922041
1978	7,994,199	5.382E+10	231,994	2697516	5296683	7994199
1979	13,043,041	6.529E+10	255,527	18956322	-5913281	13043041
1980	16,231,049	6.300E+10	251,000	15898278	332771	16231049
1981	18,970,615	7.023E+10	265,000	25248119	-6277505	18970615
1982	23,365,506	8.009E+10	283,000	36803186	-13437680	23365506
1983	25,008,155	6.812E+10	261,000	22609108	2399047	25008155
1984	28,536,969	7.095E+10	266,366	26143409	2393560	28536969
1985	34,870,804	7.377E+10	271,605	29549098	5321706	34870804
1986	42,234,263	8.551E+10	292,425	42644359	-410097	42234263
1987	51,963,184	9.464E+10	307,637	51768735	194449	51963184
1988	59,617,565	1.006E+11	317,241	57336469	2281096	59617565
1989	65,602,454	1.159E+11	340,491	70197019	-4594565	65602454
1990	72,560,283	1.344E+11	366,674	83632453	-11072170	72560283
1991	79,895,995	1.429E+11	377,978	89089996	-9194000	79895995
1992	85,191,645	1.499E+11	387,149	93365764	-8174119	85191645
1993	102,919,106	1.647E+11	405,800	101641412	1277693	102919106
1994	109,120,903	1.777E+11	421,578	108202650	918253	109120903
1995	113,917,771	1.903E+11	436,181	113916218	1553	113917771
1996	117,720,110	2.054E+11	453,181	120132838	-2412729	117720110
1997	120,775,785	2.203E+11	469,409	125630756	-4854971	120775785
1998	124,658,686	2.278E+11	477,243	128132298	-3473612	124658686
1999	128,064,368	1.891E+11	434,840	113405931	14658437	128064368
2000	130,884,861	1.985E+11	445,550	117400168	13484693	130884861
2001	133,540,554	2.079E+11	455,990	121115011	12425543	133540554
2002	136,235,349	2.165E+11	465,290	124275637	11959712	136235349
2003	138,334,141	2.980E+11	545,890	145803582	-7469441	138334141
2004	141,402,730	3.043E+11	551,630	146935631	-5532900	141402730

Invstement	141,402,730
Load change	325,406
Incremental C	$ 434.54

Slope of Corrected Regression	$ 119.33

7/25/2005 1:25 PM

REGRESSION MODEL NO. 1E Second Order Distribution Capacity-Related Investment WITH COCHRANE ORCOTT ADJUSTMENT

R SQUARED, ADJUSTED = 0.93
DURBIN WATSON STATISTIC = 1.63

After Cochrane Orcott Adjustment

X-VARIABLE COEFF.	t STATISTIC
-111693827	-6.454
$ (0.00096)	-4.191
1,179.38	6.55

Line Estimate Results

1,179.380	(0.00096)	-1.117E+08	#N/A
180.116	0.00023	1.731E+07	#N/A
0.933248	6,589,766	#N/A	#N/A
174.7593	25	#N/A	#N/A
1.52E+16	1.09E+15	#N/A	#N/A

Format of Line Estimate Results

Slope	Constant
Std Err X	Std Err b
R^2	Std Err Y
F	Deg of Free
SumSq Reg	SumSq Resid

	TRANSFORMED VARIABLES										ORIGINAL		RHO	0.48824		
YEAR	Y INVEST	X1 Squared	X2 N/A	X3 N/A	ESTIMATED (Y)'t	RESIDUAL	ADJUSTED FORECAST (Y)	ORIGINAL FORECAST (Y)'	DIFFERENCE	ADJUSTED FORECAST (Y)	ESTIMATED + RESIDUAL (Y)	DIFFERENCE	ERROR	LAGGED ERROR	ERROR^2	E(t)*E(t-1)
1976													1,425,417			
1977	3,922,041	2.43E+10	111,485	-	(3,529,029)	7,451,070	(3,529,029)	(4,524,415)	995,386	(3,529,029.4)	3,922,040.9	(7,451,070.3)	8,446,456	1,425,417	7.13E+13	1.20E+13
1978	6,079,306	2.98E+10	123,636	-	5,513,383	565,923	7,428,276	2,697,516	4,730,760	7,428,275.9	7,994,199.0	(565,923.1)	5,296,683	8,446,456	2.81E+13	4.47E+13
1979	9,139,962	3.90E+10	142,258	-	18,594,749	(9,454,787)	22,497,828	18,956,322	3,541,506	22,497,828.3	13,043,041.3	9,454,787.0	(5,913,281)	5,296,683	3.50E+13	-3.13E+13
1980	9,862,928	3.11E+10	126,242	-	7,290,254	2,572,674	13,658,375	15,898,278	(2,239,903)	13,658,374.8	16,231,048.5	(2,572,673.7)	332,771	(5,913,281)	1.11E+11	-1.97E+12
1981	11,045,984	3.95E+10	142,452	-	18,391,559	(7,345,574)	26,316,189	25,248,119	1,068,070	26,316,188.9	18,970,614.6	7,345,574.3	(6,277,505)	332,771	3.94E+13	-2.09E+12
1982	14,103,313	4.58E+10	153,617	-	25,470,178	(11,366,865)	34,732,371	36,803,186	(2,070,815)	34,732,371.3	23,365,506.3	11,366,865.0	(13,437,680)	(6,277,505)	1.81E+14	8.44E+13
1983	13,600,204	2.90E+10	122,828	-	5,285,653	8,314,552	16,693,603	22,609,108	(5,915,505)	16,693,603.2	25,008,155.0	(8,314,551.8)	2,399,047	(13,437,680)	5.76E+12	-3.22E+13
1984	16,327,013	3.77E+10	138,936	-	15,948,854	378,160	28,158,809	26,143,409	2,015,400	28,158,809	28,536,969	(378,160)	2,393,560	2,399,047	5.73E+12	5.74E+12
1985	20,937,944	3.91E+10	141,555	-	17,657,267	3,280,676	31,590,128	29,549,098	2,041,030	31,590,128	34,870,804	(3,280,676)	5,321,706	2,393,560	2.83E+13	1.27E+13
1986	25,208,977	4.95E+10	159,817	-	29,234,269	(4,025,292)	46,259,554	42,644,359	3,615,195	46,259,554	42,234,263	4,025,292	(410,097)	5,321,706	1.68E+11	-2.18E+12
1987	31,342,772	5.29E+10	164,864	-	31,924,705	(581,933)	52,545,118	51,768,735	776,383	52,545,118	51,963,184	581,933	194,449	(410,097)	3.78E+10	-7.97E+10
1988	34,247,114	5.44E+10	167,041	-	33,007,996	1,239,118	58,378,447	57,336,469	1,041,978	58,378,447	59,617,565	(1,239,118)	2,281,096	194,449	5.20E+12	4.44E+11
1989	36,494,836	6.68E+10	185,602	-	43,020,439	(6,525,603)	72,128,057	70,197,019	1,931,038	72,128,057	65,602,454	6,525,603	(4,594,565)	2,281,096	2.11E+13	-1.05E+13
1990	40,530,609	7.78E+10	200,433	-	49,895,722	(9,365,113)	81,925,396	83,632,453	(1,707,057)	81,925,396	72,560,283	9,365,113	(11,072,170)	(4,594,565)	1.23E+14	5.09E+13
1991	44,469,238	7.72E+10	198,953	-	48,748,914	(4,279,676)	84,175,672	89,089,996	(4,914,324)	84,175,672	79,895,995	4,279,676	(9,194,000)	(11,072,170)	8.45E+13	1.02E+14
1992	46,183,307	8.01E+10	202,605	-	50,262,614	(4,079,307)	89,270,952	93,365,764	(4,094,812)	89,270,952	85,191,645	4,079,307	(8,174,119)	(9,194,000)	6.68E+13	7.52E+13
1993	61,325,225	9.15E+10	216,779	-	56,060,153	5,265,071	97,654,034	101,641,412	(3,987,378)	97,654,034	102,919,106	(5,265,071)	1,277,693	(8,174,119)	1.63E+12	-1.04E+13
1994	58,871,785	9.73E+10	223,451	-	58,323,643	548,142	108,572,761	108,202,650	370,111	108,572,761	109,120,903	(548,142)	918,253	1,277,693	8.43E+11	1.17E+12
1995	60,640,694	1.03E+11	230,350	-	60,549,626	91,068	113,826,703	113,916,218	(89,515)	113,826,703	113,917,771	(91,068)	1,553	918,253	2.41E+06	1.43E+09
1996	62,101,015	1.12E+11	240,220	-	63,539,514	(1,438,500)	119,158,609	120,132,838	(974,229)	119,158,609	117,720,110	1,438,500	(2,412,729)	1,553	5.82E+12	-3.75E+09
1997	63,300,241	1.20E+11	248,148	-	65,596,830	(2,296,589)	123,072,374	125,630,756	(2,558,382)	123,072,374	120,775,785	2,296,589	(4,854,971)	(2,412,729)	2.36E+13	1.17E+13
1998	65,691,242	1.20E+11	248,059	-	65,389,600	301,642	124,357,044	128,132,298	(3,775,254)	124,357,044	124,658,686	(301,642)	(3,473,612)	(4,854,971)	1.21E+13	1.69E+13
1999	67,201,140	7.79E+10	201,831	-	51,508,561	15,692,579	112,371,789	113,405,931	(1,034,142)	112,371,789	128,064,368	(15,692,579)	14,658,437	(3,473,612)	2.15E+14	-5.09E+13
2000	68,358,846	1.06E+11	233,244	-	61,353,481	7,005,365	123,879,495	117,400,168	6,479,328	123,879,495	130,884,861	(7,005,365)	13,484,693	14,658,437	1.82E+14	1.98E+14
2001	69,637,465	1.11E+11	238,455	-	62,879,044	6,758,421	126,782,133	121,115,011	5,667,122	126,782,133	133,540,554	(6,758,421)	12,425,543	13,484,693	1.54E+14	1.68E+14
2002	71,035,647	1.15E+11	242,658	-	64,018,765	7,016,882	129,218,467	124,275,637	4,942,830	129,218,467	136,235,349	(7,016,882)	11,959,712	12,425,543	1.43E+14	1.49E+14
2003	71,818,735	1.92E+11	318,717	-	79,432,227	(7,613,492)	145,947,633	145,803,582	144,051	145,947,633	138,334,141	7,613,492	(7,469,441)	11,959,712	5.58E+13	-8.93E+13
2004	73,862,612	1.59E+11	285,105	-	71,971,225	1,891,388	139,511,342	146,935,631	(7,424,288)	139,511,342	141,402,730	(1,891,388)	(5,532,900)	(7,469,441)	3.06E+13	4.13E+13
												SUM	(1,425,417)	5,532,900	1.52E+15	7.42E+14

7/25/2005 1:25 PM

ORIGINAL REGRESSION D-W

SLOPE	0.498154873
INTERCEPT	-149344.9507
DURBIN-WATSON	1.00
R-SQUARED	0.978

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
1,425,417				2.03E+12	
8,446,456	1,425,417	7,021,039	4.93E+13	7.13E+13	1.20E+13
5,296,683	8,446,456	(3,149,774)	9.92E+12	2.81E+13	4.47E+13
(5,913,281)	5,296,683	(11,209,964)	1.26E+14	3.50E+13	-3.13E+13
332,771	(5,913,281)	6,246,051	3.90E+13	1.11E+11	-1.97E+12
(6,277,505)	332,771	(6,610,275)	4.37E+13	3.94E+13	-2.09E+12
(13,437,680)	(6,277,505)	(7,160,175)	5.13E+13	1.81E+14	8.44E+13
2,399,047	(13,437,680)	15,836,727	2.51E+14	5.76E+12	-3.22E+13
2,393,560	2,399,047	(5,487)	3.01E+07	5.73E+12	5.74E+12
5,321,706	2,393,560	2,928,146	8.57E+12	2.83E+13	1.27E+13
(410,097)	5,321,706	(5,731,803)	3.29E+13	1.68E+11	-2.18E+12
194,449	(410,097)	604,546	3.65E+11	3.78E+10	-7.97E+10
2,281,096	194,449	2,086,647	4.35E+12	5.20E+12	4.44E+11
(4,594,565)	2,281,096	(6,875,661)	4.73E+13	2.11E+13	-1.05E+13
(11,072,170)	(4,594,565)	(6,477,605)	4.20E+13	1.23E+14	5.09E+13
(9,194,000)	(11,072,170)	1,878,169	3.53E+12	8.45E+13	1.02E+14
(8,174,119)	(9,194,000)	1,019,882	1.04E+12	6.68E+13	7.52E+13
1,277,693	(8,174,119)	9,451,812	8.93E+13	1.63E+12	-1.04E+13
918,253	1,277,693	(359,441)	1.29E+11	8.43E+11	1.17E+12
1,553	918,253	(916,700)	8.40E+11	2.41E+06	1.43E+09
(2,412,729)	1,553	(2,414,281)	5.83E+12	5.82E+12	-3.75E+09
(4,854,971)	(2,412,729)	(2,442,242)	5.96E+12	2.36E+13	1.17E+13
(3,473,612)	(4,854,971)	1,381,358	1.91E+12	1.21E+13	1.69E+13
14,658,437	(3,473,612)	18,132,049	3.29E+14	2.15E+14	-5.09E+13
13,484,693	14,658,437	(1,173,744)	1.38E+12	1.82E+14	1.98E+14
12,425,543	13,484,693	(1,059,149)	1.12E+12	1.54E+14	1.68E+14
11,959,712	12,425,543	(465,831)	2.17E+11	1.43E+14	1.49E+14
(7,469,441)	11,959,712	(19,429,153)	3.77E+14	5.58E+13	-8.93E+13
(5,532,900)	(7,469,441)	1,936,541	3.75E+12	3.06E+13	4.13E+13
(1,425,417)	5,532,900	(6,958,318)	1.53E+15	1.52E+15	7.42E+14

TRANSFORMED REGRESSION D-W

SLOPE	0.159922202
INTERCEPT	-264762.792
DURBIN-WATSON	1.63
R-SQUARED	

ERROR	LAGGED ERROR	E(t) - E(t-1)	DELTA ERROR^2	ERROR^2	E(t)*E(t-1)
7,451,070				5.55E+13	
565,923	7,451,070	(6,885,147)	4.74E+13	3.20E+11	4.22E+12
(9,454,787)	565,923	(10,020,710)	1.00E+14	8.94E+13	-5.35E+12
2,572,674	(9,454,787)	12,027,461	1.45E+14	6.62E+12	-2.43E+13
(7,345,574)	2,572,674	(9,918,248)	9.84E+13	5.40E+13	-1.89E+13
(11,366,865)	(7,345,574)	(4,021,291)	1.62E+13	1.29E+14	8.35E+13
8,314,552	(11,366,865)	19,681,417	3.87E+14	6.91E+13	-9.45E+13
378,160	8,314,552	(7,936,392)	6.30E+13	1.43E+11	3.14E+12
3,280,676	378,160	2,902,517	8.42E+12	1.08E+13	1.24E+12
(4,025,292)	3,280,676	(7,305,968)	5.34E+13	1.62E+13	-1.32E+13
(581,933)	(4,025,292)	3,443,358	1.19E+13	3.39E+11	2.34E+12
1,239,118	(581,933)	1,821,051	3.32E+12	1.54E+12	-7.21E+11
(6,525,603)	1,239,118	(7,764,721)	6.03E+13	4.26E+13	-8.09E+12
(9,365,113)	(6,525,603)	(2,839,510)	8.06E+12	8.77E+13	6.11E+13
(4,279,676)	(9,365,113)	5,085,437	2.59E+13	1.83E+13	4.01E+13
(4,079,307)	(4,279,676)	200,370	4.01E+10	1.66E+13	1.75E+13
5,265,071	(4,079,307)	9,344,378	8.73E+13	2.77E+13	-2.15E+13
548,142	5,265,071	(4,716,930)	2.22E+13	3.00E+11	2.89E+12
91,068	548,142	(457,074)	2.09E+11	8.29E+09	4.99E+10
(1,438,500)	91,068	(1,529,567)	2.34E+12	2.07E+12	-1.31E+11
(2,296,589)	(1,438,500)	(858,090)	7.36E+11	5.27E+12	3.30E+12
301,642	(2,296,589)	2,598,231	6.75E+12	9.10E+10	-6.93E+11
15,692,579	301,642	15,390,937	2.37E+14	2.46E+14	4.73E+12
7,005,365	15,692,579	(8,687,214)	7.55E+13	4.91E+13	1.10E+14
6,758,421	7,005,365	(246,944)	6.10E+10	4.57E+13	4.73E+13
7,016,882	6,758,421	258,461	6.68E+10	4.92E+13	4.74E+13
(7,613,492)	7,016,882	(14,630,374)	2.14E+14	5.80E+13	-5.34E+13
1,891,388	(7,613,492)	9,504,880	9.03E+13	3.58E+12	-1.44E+13
0	(1,891,388)	(5,559,682)	1.77E+15	1.09E+15	1.74E+14

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-91: Refer to the Company's response to DTE 15-5. The Company states that the logarithmic relationship using design day demand and customer count as presented in the Company's response to DTE 2-1 offers a better statistical alternative than the one suggested in DTE 15-5.

a) explain in detail what the Company means by "a better statistical alternative";
b) provide the marginal cost estimates from the logarithmic relationship suggested in the Company's response to DTE 2-1 and identify the marginal cost estimates that the Company would use in this proceeding (that is, would it be the average or incremental marginal cost estimates from the Company's response to DTE 15-5 or the marginal cost estimates from the logarithmic relationship discussed in the Company's response to DTE 2-1?).

Response: a) The logarithmic relationship exhibited a higher R^2 (0.96 instead of 0.93) and a lower sum of the squared residuals (36% lower); while employing the same number of degrees of freedom and significant t-values for all coefficients.

b) Marginal Distribution Plant Capacity-Related Investment_{2004} =
$263.58 per Design Day Dt + $1,303.17 per Customer

As discussed in the Company's responses to DTE 2-1 and DTE 15-5, the econometric analysis of distribution capacity-related investment is flawed by data consistency issues. The Company believes its filed marginal cost estimate using prospective additions for reinforcement and incremental average extension costs provide a better basis for estimating marginal costs.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-92: Please describe the main factors or variables that contributed to the annual variations in the total capacity distribution plant for Bay State Gas Company.

Response: The following is a list of the main factors or variables that contributed to the annual variations in the total capacity distribution plant for Bay State Gas Company.

1. Actual Load added
2. Developments planned but not fully constructed
3. Interest rates
4. Engineering estimates of growth-related distribution plant investments
5. Construction cost escalation rates
6. Amount of available capacity at locations in the service territory experiencing growth
7. Individual large industrial plant additions
8. DTE customer connection (customer contribution) policy
9. Bare steel and cast iron replacements.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-93: Refer to the Company's response to DTE 15-6. Please explain what the Company means by "Internal Cost Accounting Reports". Indicate whether the costs in these internal cost accounting reports are identified and booked consistent with the Uniform System of Accounts for Gas Companies.

Response: In order to assist the Company's management, the Bay State accounting system currently provides Activity Based Costing (ABC) reports that indicate monthly data for various activities including costs, number of units and unit costs. These reports are generated by the general ledger system, the same system that provides accounting reports in accordance with USOA. However, the ABC reports consolidate the reporting of capital and expense items and report the unit costs for construction activities as well as maintenance activities. In the case of mains construction, the ABC system separately reports construction costs for New Mains as well as Replacement Mains.

The USOA reports additions and retirements to mains investments. The additions would represent the sum of New Mains and Replacement Mains from the ABC reports. Since the unit costs for replacement mains are markedly higher than for new mains, this individual data is very helpful in estimating the costs for main extensions in the marginal cost study.

The ABC system contains annual cost data dating back to 1992. Prior to that, the Company employed other management reporting software to assist in the budgeting and control functions. However, the need for past budgeting reports is limited and record retention policies do not call for retention of this data. Consequently, it is impossible to generate 30 years of consistent data other than USOA reports from the general ledger.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-94: Refer to the Company's response to DTE 15-10. Please complete the summary table presented by adding the main results from the regression equations (e.g., marginal cost estimates, t-statistics of estimates, DW statistics, Adjusted R^2). In addition, state the reasons why the Company would select or reject each of the regression equations.

Response: See Attachment RR-DTE-94, which shows the regression equation statistics.

As explained in DTE 2-1, part b) of the Company's response to DTE 15-10 and part b) of RR-DTE-91, data quality issues make econometric analyses less preferable than the method chosen by the Company to estimate marginal distribution capacity-related costs.

Statistics for Regressions in DTE-15-10

	Form	Dependent Variable	Independent Variable	Marginal Cost Estimate	R-Squared	t-Statistics	Durbin-Watson Statistic
1	Y=a+bx	Cumulative Growth-related Distribution Investment ($2004)	Firm Design Day Demand	$ 455.16	0.89	a = -6.96 b = 14.38	1.30
2	Y=a+b*ln(x)	Cumulative Growth-related Distribution Investment ($2004)	Natural log of Firm Design Day Demand	$ 313.35	0.93	a = -17.67 b = 18.38	1.54
3	Y=a+bx+cz	Cumulative Growth-related Distribution Investment ($2004)	Firm Design Day Demand and Firm Customer Count	$170.57 per DD Dt and $913.16 per Cust	0.95	a = -9.8 b = 3.33 c = 6.03	1.50
4	Y=a+b* ln(x) +c* ln(z)	Cumulative Growth-related Distribution Investment ($2004)	Natural log of Firm Design Day Demand and Natural log of Firm Customer Count	$263.58 per DD Dt and $1303.17 per Cust	0.96	a = -14.01 b = 3.9 c = 5.3	1.49

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-95: Refer to the Company's response to DTE 2-3, at Attachment 1, p. 2 of 18. The Company selected $10.57 as the marginal O&M capacity-related distribution cost (the predicted average O&M capacity-related distribution cost for 2004). At the same time, the Company reported an average O&M capacity-related distribution cost of $11.39 for 2004 (<u>see</u> Exh. BSG/JLH-3 at Schedule 3-5, p.1). In view of the Company's statement that the $11.39 estimate reflects the ongoing savings resulting from the replacement of mains that are costly to maintain (see the Company's response to DTE 15-17), explain why the Company selected the $10.57 estimate instead of the $11.39

Response: Both the observed actual unit cost and the statistical projection of unit cost for 2004 reflect the ongoing savings resulting from mains replacement. As shown in the Company's response to DTE 2-3, the time series analysis of unit costs corrected for serial correlation displayed a statistically significant declining trend. Therefore, the econometric projection was chosen to estimate marginal costs.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-96: Refer to the Company's response to DTE 15-17. Please discuss why the Company used an average cost, and not a marginal cost, as an estimate of the marginal O&M capacity-related distribution expenses. Please discuss how good a proxy (of the marginal cost) the average cost estimate can be.

Response: The Company attempted several regressions using annual O&M capacity-related distribution expenses, not unit costs, as the dependent variable, but could not develop a meaningful prediction equation. Using unit costs allowed the development of a meaningful econometric specification. Current average costs are frequently used in rate cases to estimate marginal O&M costs. The use of a valid time series prediction of unit costs represents an improvement over current average costs.

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RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

RR-DTE-97: Please compute the percentage of O&M capacity-related distribution marginal cost estimate with respect to the total marginal cost estimate (the total marginal cost estimate used for rate design purposes).

Response: Marginal capacity-related distribution O&M expenses are estimated at $10.57 per design day Dt. Schedule JLH 3-9 shows delivery-related marginal costs to be the sum of pressure support-related local production costs ($10.77), mains reinforcement costs ($26.60) and mains extensions costs ($56.90). Thus, the requested percentage is 11%.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

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Date: July 29, 2005

Responsible: Danny G. Cote, General Manager

RR-DTE-105: Regarding response to DTE-3-21, calculate the total incremental dollar costs for the project in List #1. Include rough capacity calculations provided by engineer.

Response: The project identified in list one (Short St. Taunton) described the replacement of 4381 feet of 2” bare steel main with 6” plastic main. The incremental portion of the cost per foot to replace the 2” bare steel with 2” coated cathodically protected steel (which would be like-for-like replacement) would be $10.52 based on 2005 construction and material costs, (see Attachment RR-DTE-105, Section 1, Column 2” CS, Row “Total Material & Cont. Charges”).

The incremental portion of the cost for 6” plastic is $11.63 per foot (see Attachment RR-DTE-105, Table 1, Column 6” PE, Row “Total Material & Cont. Charges”).

Thus the cost per foot difference between 2” steel and 6” PE replacement is $1.11 per foot, or $4,891.91.

Regarding Capacity, the flow through 1 mile of 2” steel at 200 PSIG is 80,522 CFH (see Attachment RR-DTE-105, Table 4, (B) Steel Mains, Column 200 psig, for 2” steel).

The flow through 6” PE at 99 PSIG is 582,295 CFH, (see Attachment RR-DTE-105, Table 4, (A) PE Mains, Column 200 psig, for 2” PE), resulting in an increase in capacity of 501,733 CFH.

Therefore, at an incremental cost of $4891.91 (or $1.11 per foot), which was roughly 3% of the total project cost, the capacity of these facilities was increased by a factor of 7.

BAY STATE GAS COMPANY
COST ANALYSES, STEEL VS PE MAINS

TABLE (1): MATERIAL & CONTRACTOR CHARGES

DESCRIPTION	2" PE ($/ft)	2" CS ($/ft)	4" PE ($/ft)	4" CS ($/ft)	6" PE ($/ft)	6" CS ($/ft)	8" PE ($/ft)	8" CS ($/ft)
Material	$0.51	$3.07	$1.72	$8.21	$3.73	$9.25	$6.34	$14.23
Contractor Charges	$6.25	$7.45	$6.60	$8.10	$7.90	$9.20	$10.75	$11.45
Total Material & Cont. Charges	$6.76	$10.52	$8.32	$16.31	$11.63	$18.45	$17.09	$25.68

TABLE (2): COST DIFFERENCES BETWEEN VARIOUS SIZES & TYPES

$ Difference = (Material + Contractor Charges) of more expensive main - (Material + Contractor Charges) of cheaper main

Flow Difference = (Flow @ 200 psig Steel main) - (Flow @ 99 psig PE main)

MAIN SIZES	COST DIFFERENCES ($)	FLOW DIFFERENCES (CFH)
2" Steel vs. 4" PE	-$2.20	-122,411.81
2" Steel vs. 6" PE	$1.11	-501,773.11
4" Steel vs. 6" PE	-$4.68	-105,752.68
4" Steel vs. 8" PE	$0.78	-717,257.18
6" Steel vs. 8" PE	-$1.36	1,969,988.17

NOTE: **(-) Cost Difference means:** it is more expensive to replace with a steel main than a PE main
(+) Cost Difference means: it is more expensive to replace with a PE main than a steel main
(-) Flow Difference means: the flow capacity of a steel main @ 200 psig is less than a PE main @ 99 psig
(+) Flow Difference means: the flow capacity of a steel main @ 200 psig is greater than a PE main @ 99 psig

BAY STATE GAS COMPANY

COST ANALYSES, STEEL VS PE MAINS

TABLE (3): INTERNAL DIAMETER DIFFERENCES BETWEEN VARIOUS SIZES & TYPES

PIPE SIZE	ID (Steel Main)	ID (PE MAIN)
2" MAIN	2.067	1.943
4" MAIN	4.026	3.682
6" MAIN	6.25	5.421
8" MAIN	8.187	7.055

Steel Wall thickness
0.154
0.237
0.188
0.219

TABLE (4): GAS FLOW VOLUME PER 1 MILE

(A) PE MAINS

PE Main Sizes	@ 60 psig (CFH)	@ 99 psig (CFH)
2" PE MAIN	21,647.43	35,552.11
4" PE MAIN	123,565.20	202,934.20
6" PE MAIN	354,555.60	582,295.50
8" PE MAIN	726,896.10	1,193,800.00

(B) STEEL MAINS

STEEL Main Sizes	@ 60 psig (CFH)	@ 99 psig (CFH)	@ 200 psig (CFH)
2" STEEL MAIN	24,414.61	39,444.76	80,522.39
4" STEEL MAIN	144,489.09	233,439.66	476,542.82
6" STEEL MAIN	466,926.72	754,376.75	1,539,981.80
8" STEEL MAIN	959,269.28	1,549,815.87	3,163,788.17